AN ASSESSMENT OF TOTAL ENERGY
SYSTEMS FOR NAVAL INDUSTRIAL
AND NON-INDUSTRIAL ACTIVITIES.

Raymond Louis Mathewson

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by

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Bachelor of Engineering (Marine)
State University of New York Maritime College
(1970)

Submitted in Partial Fulfillment
of the Requirements for the
Degree of

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AN ASSESSMENT OF TOTAL ENERGY SYSTEMS FOR NAVAL INDUSTRIAL AND NON-INDUSTRIAL ACTIVITIES

BY

RAYMOND LOUIS MATHEWSON, JR.

Submitted to the Department of Ocean Engineering on May 12, 1978, in partial fulfillment of the requirements for the Degrees of Ocean Engineer and Master of Science in Naval Architecture and Marine Engineering.

ABSTRACT

The total energy concept has been proposed as a possible system alternative towards reducing the cost of providing the electrical and thermal power requirements of United States Naval Activities. An overview of the key factors influencing the possible shift to a total energy system approach is presented. The importance of fuel availability and accurate load profile determination are addressed. Co-generation, including peaking operations and select energy systems are analyzed in addition to total energy systems independent of the commercial utility grid, and the value of a reliability and availability analysis as another basis for comparison and selection between alternative system designs is demonstrated. The design and operational characteristics of the three principal generator prime movers--steam turbines, gas turbines and reciprocating internal combustion engines are described. The environmental factors which can influence the successful application of a total energy system installation are also considered. The background of the total energy concept and the history of its development in this country is reviewed in order to explain the thrust of future research and development which is required.

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CHAPTER 1

INTRODUCTION

The objective of a Total Energy System (TES) is to provide both thermal and electrical power through on-site electrical generation plants with heat recovery and/or generation supplying all or part of the energy demands of a complex. It has long been recognized that on-site power generation which utilizes recovered low level heat could reduce the annual operating costs of a facility. The significance of these reductions has become more apparent in recent years.

1.1 Historical Background

1.1.1 Escalation of Electrical Power Costs

During the last months of 1973, the Organization of Petroleum Exporting Countries (O.P.E.C.) tripled the price of crude oil. Because the electric utility companies in Massachusetts imported 92% of their oil, one of the immediate impacts of the O.P.E.C. oil price increase was a swift jump in the fuel adjustment charge on electric bills. Boston Edison customers, both residential and large industrial and commercial establishments, paid a 396 percent increase in fuel charges between September, 1973, and July,

1974. In other states, the impact of the higher oil prices on consumers' electric bills was also dramatic, if not so severe.

In addition to increased fuel oil costs, there are also several proposals before the Federal Power Commission and individual State public utility regulatory authorities (e.g., the Department of Public Utilities in Massachusetts) to change the existing electrical rate structures. Massachusetts voters defeated a referendum in November, 1976, that would have provided a simple solution to the problem of how to price electricity. The referendum question would have created a "Flat Rate" electric schedule, a uniform price per kilowatt hour (KWh), which would be charged to all electric customers.

The shift in revenues resulting from the Flat Rate would be about $70 million per year (about 6 percent of the total electric revenues in the state).[1] Electric bills for industries and large commercial establishments would rise an average of 24 percent. The hardest hit would be those firms with a high power demand and long operating hours, since the Flat Rate electric schedule would prohibit any discount for long hours use of a steady level of power. Hospitals would face a 34 percent increase; office buildings, 27 percent; supermarkets, 24 percent; colleges and universities, 33 percent; manufacturing firms, 34 percent.

Electricity rate reform promises to be a recurrent issue in each of the 50 states. The Flat Rate Electric Bill proposal in Massachusetts, even though it was defeated in the general election in 1976, is likely to be reflected in other forms such as "Peak Period Pricing" or "Time of Day Pricing" in future rate proposals. Presidential efforts to promulgate national standards for rate design have failed to make it through congressional committees,[1] and so each state will have to set its own standards for reform and its own timetable for that reform action.

This indicates the timely importance to determine more cost effective means of supplying the electrical energy demands at Naval facilities throughout the United States.

1.1.2 Results of Previous Studies

In November, 1973, the first of a series of reports (references 2, 3 and 4) was prepared for the Defense Advanced Research Projects Agency in Arlington, Virginia, by the Booz, Allen and Hamilton Energy Resources Group in Bethesda, Maryland. These reports described an assessment of alternative strategies for optimizing energy supply, distribution, and consumption on naval bases.

After an extensive review of Navy-wide utility data and visits to two representative bases, a set of potentially useful, near-term energy conservation strategies were

identified.[2] Table 1-1 summarizes the results obtained for the six near-term strategies which were selected. The primary fuel savings reflect reduced levels of electric power or steam consumption. Some of these benefits could be realized by a commercial power company and not by the Navy directly.

Table 1-1 indicates the substantial energy savings that are possible for CONUS Navy facilities using only these six near-term energy conservation strategies. A conservative estimate of the benefits from these strategies indicates that approximately 11 percent of the CONUS Navy's delivered energy could be saved.

The second report of the series was submitted in January, 1974.[3] This report summarized an assessment of five advanced energy conservation strategies including a technology assessment, a discussion of applicability to the Navy, a discussion of costs and benefits, and recommendations for Navy implementation of each. These five advanced energy conservation strategies are solar energy, automated building controls and monitoring systems, electrochemical sources (fuel cells), advanced transportation technology and total energy systems.

There were four significant recommendations made in regards to solar energy applications. These recommendations were to (1) begin procurement of solar hot water heating

TABLE 1-1 Summary of Energy Savings and Net Economic Benefits Resulting from Implementation of Six Conservation Strategies Throughout CONUS Navy Shore Facilities [2]

Strategies	Savings in Delivered Energy Per Year	Net Energy Savings of Primary Fuels BTU x 10^{12}/yr	Net Benefit $ million	Breakeven Time, Years
(1) Solid Waste for Steam	12.7×10^{12} BTU	12.70	84.0	4.8
(2) Improve Steam Distribution Systems	2.3×10^{12} BTU	2.30	35.4	1.5 to 2.2
(3) Building Improvements	3.2×10^{12} BTU	6.60	24.5	7.6
(4) Metering of Family Housing	170×10^{6} KWh	1.80	14.0	1.2
(5) High Efficiency Window A/C Units	7.8×10^{6} KWh	0.03	0.5	6.0
Optimization of Lighting Energy Use	267×10^{6} KWh	2.72	118.0	1.0
TOTAL	18.2×10^{12} BTU 444.8×10^{6} KWh	26.15	276.4	

NOTES:

The generation efficiencies assumed in making these estimates were 80% for steam and 33% for electricity.

The prime fuel savings calculated for the building improvements strategy includes an assumed 30% loss in the steam distribution system.

(1) Assumed only 50% recovery of available BTU content in the waste.
(2) These are low estimates; the two breakeven times are for implementation periods of 1 and 4 years.
(3) These results are for the case of 3.5 inches of ceiling insulation only.
(4) Results are based on a 20% decrease in electric consumption when metering is installed.
(5) Results are based on 2,000 hours of operation per year and on improvement in average energy efficiency ratio to only 7.5.

equipment; (2) establish a center for solar energy responsibility; (3) conduct a solar energy feasibility study to compile and evaluate solar energy data and (4) revise building specifications and develop a solar energy design manual and a solar energy education program.

With regards to automated building controls and monitoring systems, because of the high cost of control centers and the fact that each installation is custom built, it was recommended that further studies be made of the feasibility of installing control centers in selected Navy facilities.

The suggestion was made that major research and development support from both the government and private sectors would be required to achieve significant application of fuel cells to electric power supply systems within the early 1980's.

The following two major recommendations were presented for conserving energy in transportation. The first recommendation was that the Navy implement, on a demonstration basis, a Dial-A-Bus system on at least two of its major bases, and review the results of the demonstration at the end of 1.5 years. The second recommendation was that the Department of Defense should support, at least in part, a program to develop a light-duty diesel engine that could be used by DOD motor

vehicle fleets to conserve fuel. It was recommended that this program be implemented in three phases as follows:

Phase I: Feasibility Assessment

Phase II: Development of Preproduction Prototypes

Phase III:Tooling for Mass Production of Engines

With regards to total energy systems, the recommendation was made that the Navy monitor studies and development efforts which are currently in progress by HUD and other government and private agencies.

1.2 Total Energy Systems

Total energy systems are on-site electrical generation plants with heat recovery and/or generation supplying all or part of the energy demands of a given complex. There is often a thermodynamic and economic advantage when thermal and electrical power are produced simultaneously. The thermal power is actually a by-product of the electrical power production and is readily available with little extra cost. By recovering this waste heat and using it, the overall efficiency of the thermodynamic system is increased.

Traditionally, total energy systems have been steam plants, where steam is extracted from the turbine for heating and other purposes after it has delivered some of its energy to the turbine to produce electricity. These power plants

are termed extraction units, process steam units or district heating power plants, depending on the application.

More recently gas turbines and diesel engines have been utilized in total energy system configurations. In these engines, some of the energy normally rejected in the form of exhausted gases is partially recovered for heating purposes by means of heat exchangers placed in the exhaust gas streams.

Because of the large heat loss with conventional power generation, the potential economic and energy savings which may be achieved from a total energy system are great. To achieve this potential, however, a rather specialized set of circumstances must exist.

Unlike a conventional, single-purpose power plant, total energy systems must be "site-specific". That is, they must be custom designed to fit a specific institutional situation. The system configurations with the highest correlation of the thermal and electrical loads will also have the highest overall thermal efficiency and will consume the least amount of fuel.

The potential of the total energy system concept lies in the elimination of major losses in the conversion of energy from its original chemical forms into its end use forms. The

total energy concept achieves this improvement by exploiting the heat which is usually lost in the original conversion of chemical energy to other forms and by shortening the chain of energy conversion steps which exist between the present source and end user.

The basic incentive to consider on-site generation of electricity is the possible margin between the cost of power purchased as electricity and the operating cost of the facility required to generate the same power. When this margin is large enough to defray the capital expenditure involved, the decision to construct an on-site total energy facility is indicated.

There are also other secondary advantages of total energy system installations which are relevant to Naval installations.[3]

Local generation of electric power provides security against failure or overload of the main power grid. Some critical applications, such as computer or communication installations, often prefer the use of local generation because public power may have excessive fluctuations or transients.

Local plants can provide high frequency electric power (400 Hertz and greater) which can improve the efficiency of flourescent lighting by about 30 percent as

well as reduce the cost of required flourescent fixtures. High frequency power has also been shown to add to the life of incadescant lamps.

Total energy systems installations have the advantage for military installations that certain prime movers such as diesel and gas turbine engines can readily be adopted for use on standard ship and aircraft fuels.

The total energy concept is compatible with many new and emerging technologies which are being evaluated for specific roles in energy conservation systems. These technologies include: eutectic heat storage; thermoelectric and solar power generation; heat transfer devices such as heat pipes and heat wheels, and advanced thermodynamic cycles such as the closed Brayton cycle, organic Rankine cycle (e.g., the Sundstrand cycle) and the Stirling cycle.

Most Naval shoreside facilities have been in existence 25 years or more, and their existing steam heating and hot water supply systems will present minimal conversion problems.

Navy Public Works Centers have large inventories of energy generating equipment and permanent staffs of operating personnel that could be employed in total energy applications.

On a 24-hour basis, naval base loads as a whole may be more constant than the loads of comparable civilian environments. For instance, at the Great Lakes Naval Base in Illinois,

the heavy classroom load of the daytime is replaced by increased demand from on-base housing at night.[3]

It should be noted that the first three of these secondary advantages apply to any on-site power plant, whether or not it is configured as a total energy system.

There are several drawbacks and practical limitations to the total energy concept, the most significant of which are the following.

The installation of a total energy system will require a considerable capital investment, i.e., a higher initial cost than would be required for alternative systems performing only a single function. The capital investment per kilowatt is also greater for a total energy plant, or for any other small plant, than it would be for a large central station plant. However, the economic attractiveness of a total energy system lies in the prospect of reduced life cycle costs and an early payback of this initial capital investment through reduced future utility costs.

The total energy system achieves its greatest overall system efficiency by utilizing the waste heat which is a byproduct of electrical power generation. This requires that the ratio of thermal to electric energy of the user load be matched closely with that of the generating plant, which is often difficult to achieve.

Statistical considerations indicate that a small power distribution system is more susceptible to relative fluctuations in load then is a large system. This in turn requires a greater relative amount of excess capacity in the small system in order to handle peak loads and load fluctuations.

A small power plant which is dedicated to a single facility is paticularly vulnerable to wide changes in energy demand and future growth at that facility. Over-designing a plant in the first place is not an acceptable solution because of the capital costs involved and the fact that the prime movers become inefficient when operated at part load.

Unlike a majority of capital investments, a power plant cannot be forgotten after it is installed. The continuing need for equipment maintenance makes the facility vulnerable to inadequate training of operators, strikes, shortages of spare parts and other operational problems.

Many of the general advantages and disadvantages of total energy systems apply differently to the Navy than to civilian installations. Table 1-2 summarizes these points and shows how they apply to the Navy in particular.

TABLE 1-2 Significance of Total Energy System Advantages and Disadvantages for Naval Facilities [2]

ADVANTAGES	IMPACT ON NAVAL APPLICATION	DISADVANTAGES	IMPACT ON NAVAL APPLICATION
Independent from central power	Very Significant. In view of possible degradation of public power in the future. Better for military security.	Capital investment	Moderately Significant to Very Significant. Depending on size of installations. Less of a factor than for comparable civilian installations.
High Frequency Power	Moderately Significant. Exploitation would require retrofit of equipment and new electric distribution system.	Fixed thermal/ electrical energy ratio	Moderately Significant to Very Significant. Depending on base load characteristics, type of installation, and existing equipment.
Use of standard military fuels	Very Significant. In view of Navy's goal of fuel standardization and possible future fuel procurement difficulties.	Fluctuations in load	Moderately Significant. This problem can be minimized because a military facility can control load shedding and distribution as well as generation.
Compatible with emerging technologies	Moderately Significant. In view of Navy's commitment to energy conservation. Many new technologies do not require presence of total energy systems.	Need to predict future demand	Slightly Significant. Size of most Naval facilities is static, and changes are scheduled well in advance.
		Continuing operational burden	Not Significant. In most cases since public works plants already require added staff. At outlying installations, trained military personnel are available.

In FY72, CONUS naval facilities consumed approximately 20×10^9 kilowatt-hours of electricity, more than 70 percent of which was purchased from commercial utilities.[3] This represents a significant opportunity for energy and dollar savings through on-site generation of electrical power. For every mill (1/10th of a cent) savings per kilowatt-hour, the Navy could save $20 million per year, and for every percent of electric fuel energy savings, a total of 1,000 barrels of oil equivalent per day or 365,000 bbls per year or $1.4 million (1974 dollars) could be saved.[3] Thus, there is a significant incentive to consider on-site electrical generation through total energy systems.

1.3 Major Design Elements

There are several prominent areas which must be addressed in the feasibility studies during the conceptual design stage of a total energy system. One of the most important of these is the type of fuel which is to be utilized in the plant, and predictions of that fuel's future availability and price.

Many studies have been completed by the Department of Defense and other government agencies and private consultants regarding the future availability and price of the three major types of fuel -- oil, coal and natural gas.[2,3,4,5,6,7,8]

Important considerations in the selection of the type of fuel to be utilized are the continued escalation of fuel oil costs and the Federal governments present plans of enforcing a shift to coal as the primary fuel for industrial use and power generation.

Consideration should also be given to the utilization of secondary fuels. The prices of conventional fossil fuels are increasing at a dramatic rate and the availability of these fuels is becoming increasingly uncertain, especially in the case of natural gas. It follows that if a source of alternate fuel is readily available, it would be to the Navy's advantage to incorporate it as a source of energy. For example, recent studies made at Central Michigan University recommended the installation of a steam plant with boilers capable of firing coal, wood, oil and gas in a total energy system at the University.[7] This recommendation was based on the local availability of coal and wood chips to the University at energy costs which were highly favorable when compared to oil. The cost of wood chips was extremely competitive with the more conventional fuels, and the plant selection was based on the use of this type of fuel. Studies such as this must be made for each individual location and should reflect the availability of secondary fuels in those localities.

The daily and seasonal load profiles for both the electrical and thermal loads at the facility must also be addressed in detail. A total energy system must be designed to match these load profiles as close as possible, because the greater overall thermal efficiency of a total energy system is based on the correlation of the thermal and electrical loads. This topic is addressed in detail in Chapter 2.

The advantages of various system configurations, including cogeneration and total energy systems independent of the commercial utility grid are presented in Chapter 3. The importance of a reliability and availability analysis as another basis for comparison and selection between alternative system designs is also demonstrated.

The following chapters describe the design and operational characteristics of the three principal generator prime movers -- steam turbines, gas turbines, and reciprocating internal combustion engines. Characteristics of primary importance are the off-design performance and the range of the thermal/electric (T/E) ratio which can be satisfied by each.

The environmental factors which can impact the successful application of a total energy system installation are also considered. The purpose is to point out those areas

of environmental impact which are peculiar or significant to the total energy system installation.

The background of the total energy concept and the history of its development in this country is reviewed in order to explain the thrust of future research and development which is required.

CHAPTER 2

LOAD PROFILE ANALYSIS

A conceptual design and feasibility study for total energy systems must necessarily begin with a thorough assessment of the thermal and electrical loads to be supplied. An evaluation of the energy needs will improve the assessment of the total energy systems to satisfy these needs. Such an assessment should include, if possible, the increased energy requirements associated with the planned future growth of the facilities.

2.1 Load Profile Objectives

The objective of the load analysis is the definition of the magnitude and time characteristics of the mechanical, electrical and thermal loads in order to better determine equipment types and sizes. Specific outputs of the load analysis are:[5]

1. Direct mechanical energy requirements -- hour by hour, by day of the week and time of the year, and by their schedule of utilization if utilization varies.

2. Electrical loads as functions of these same time factors.

3. Thermal loads, categorized by temperature and temperature differential, as functions of these same time factors.

While many users of energy at Naval bases are characteristically process or industrial loads, the majority of naval energy consumption is for environmental loads.[3] Environmental loads are considered to be those for housing, classroom buildings, offices and other personnel-oriented structures.

Steam is currently the medium of choice for space heating, even in the absence of heat recovery at the power plant. Fortunately, steam and hot water heating are very effective ways of utilizing the heat output of total energy plants.

Unfortunately, the demand for space heating, and to a lesser extent for hot water heating, is seasonal in nature. In most cases, these thermal loads are significantly less during the summer months than the winter months.

The standard approach to this problem of excess heat generation in the summer has been to employ steam absorption air conditioning units rather than rotary units which require either electric motor drive or direct mechanical drive by a

prime mover. In this manner, a major part of the energy load during the summer may be shifted from electricity to steam, which will bring the thermal/electric ratio of the load more in line with that of the generating plant.

2.2 Navy Load Profile Data From Two Test Bases

In order to determine in detail the Navy's current energy-use patterns at the base level, two Naval bases were selected by the Naval Facilities Engineering Command (NAVFAC) for an in-depth survey of their energy consumption patterns.[2] These bases were the Great Lakes Naval Training Center and the Pensacola Naval Air Rework Facility. Great Lakes was selected because it is a people oriented training facility, and Pensacola because it is a typical industrially oriented facility. Table 2-1 lists the various types of Naval activities, and the percentage of total electrical and steam consumption of each.

The energy consumption patterns for the Great Lakes and Pensacola bases are presented in reference [2]. The electrical power consumption at Great Lakes remained relatively constant during the year, whereas the energy used to generate steam (which is primarily used for space heating) increased significantly during the winter. In contrast, the Pensacola base demonstrated a peak in electric power consumption during

TABLE 2-1 Percentage of Total Energy Consumption by Type of Activity.[2]

Primary Activity (Functional Units)	Electricity Consumption	Steam Consumption
Air Stations	18	22
Hospitals	8	5
Shipyards	19	23
RDT&E	5	2
Communications	2	1
Ship Stations	5	9
Training/Reserve	3	3
Miscellaneous	40	35
	100	100

the summer months, which was not apparent at Great Lakes. In addition, the energy used to generate steam at Pensacola also peaked during the summer months rather than the winter. The thermal energy usage appeared to be proportional with the electrical energy requirements and the thermal electric ratio appeared to be fairly constant over the course of the year at Pensacola.

This information was used to complete detailed calculations of the costs and benefits of various conservation strategies at each base. These results were then extrapolated to the CONUS Navy level by employing a trend analysis methodology. This methodology is based on energy-use correlations within, and wherever possible between, Naval functional units such as shipyards, training stations, air stations and medical centers.

These correlations were established from an analysis of available Navy data, and were developed around energy-use patterns and several identifiable characteristics such as Navy category codes, weather conditions, population, floor area, etc. The energy data was normalized by dividing by the number of heating or cooling degree days respectively in order to remove as much climate dependence as possible from the steam and electricity totals. The quantities which ultimately showed the most consistant results were:

Steam Heat/Heating Degree Days Vs. Base Floor Area

Steam Heat/Heating Degree Days Vs. Population

Electricity/Cooling Degree Days Vs. Base Floor Area

Electricity/Cooling Degree Days Vs. Population

Population Vs. Base Floor Area.

In most cases, the normalized energy related quantities for individual Navy activities were correlated within ±20 percent by a single variable. The best trend correlations were achieved using base floor area in square feet as the independent variable. The trends based on population and population density were used to analyze the reasons for any major deviations which occurred.

The two major results from this energy load data analysis were as follows. First, the results indicated that energy-use trends could be extrapolated from the base level to the national level. These trend analyses could form the basis for a total Navy energy model which would be a very valuable tool for measuring the impact of any energy conservation program.

The second result discovered in the course of the research was that in spite of the massive amount of records and reports compiled and stored by the Navy, there were large gaps in major energy data areas.[2] These gaps hampered the

efforts to describe energy consumption patterns and to predict with a high degree of accuracy the impact of the proposed conservation strategies. The main sources of Navy energy consumption data and their deficiencies are detailed in reference [2].

2.3 Load Model Development at MIT

A feasibility study and conceptual design for a total energy system was recently completed for MIT.[9,10] The MIT campus is very similar, both in physical layout and operating profiles, with Naval training facilities such as the Great Lakes Naval Training Center.

For the purpose of system evaluation, a load model was required to predict accurately the transient and off-design performance of the various candidate energy systems. The motivation for this load model development was the desire to simulate the campus energy requirements along with models of various total energy schemes for the purpose of determining the relative cost advantages of each.

MIT is fortunate to have available within the Department of Physical Plant the detailed steam and electrical power usage data from which load profiles could be constructed. A considerable effort was devoted to the analysis of these data, with the result that comprehensive,

analytical daily steam and electrical demand load profiles were developed for all seasons of a model year. The details of this load model development are presented in reference [11] and summarized in this section.

2.3.1 Steam Load Profile Development

Reduction of the MIT data began with an analysis of the steam load data because it was felt that this data could be most easily correlated with outside ambient parameters (temperature, wind and humidity).

It was verified that for days with an average temperature less than 65°F, wind chill has an augmenting effect on daily total steam flow. In order to predict the daily total steam flow as a function of temperature alone, the average daily temperature was corrected for the effects of wind velocity, above or below the 12.5 mph standard, with a wind velocity-temperature correction chart developed by Professor A.L. Hesselschwerdt for the MIT Physical Plant.[12]

No correlation could be found between relative humidity and daily total steam flow. There was not even consistent evidence that higher humidity contributes to an increased air conditioning load.

The daily steam flow data refinement was accomplished using the "MIT-SNAP" program [13], which is an interactive data analysis system for the IBM-370 computer. Weekdays and

weekends/holidays were input as separate groups. All ambient temperatures were corrected to the 12.5 mph wind velocity standard base. A least-squares multiple regression was specified for second, third, fourth and fifth order polynomials with the ambient temperature as the dependent variable and daily total steam flow as the independent variable.

The best polynomial fit for both the weekday and weekend data was obtained with the third order regression analysis. Plots of the weekday steam demand data versus temperature and the fitted curve for this data are shown in figures 2.1 and 2.2 respectively, and the regression statistics for this curve fit are shown in table 2.2. Definitions of the regression statistics are as follows:

$$R^2 = 1 - \frac{(y_i - \hat{y})^2}{(y_i - \bar{y})^2} \tag{2.1}$$

$$F = \frac{R}{1-R^2} \frac{N-k}{k} \tag{2.2}$$

where

y_i = input data point

$\hat{y}$ = fitted data point

$\bar{y}$ = arithmetic mean of all input data

N = number of data points

k = degrees of freedom

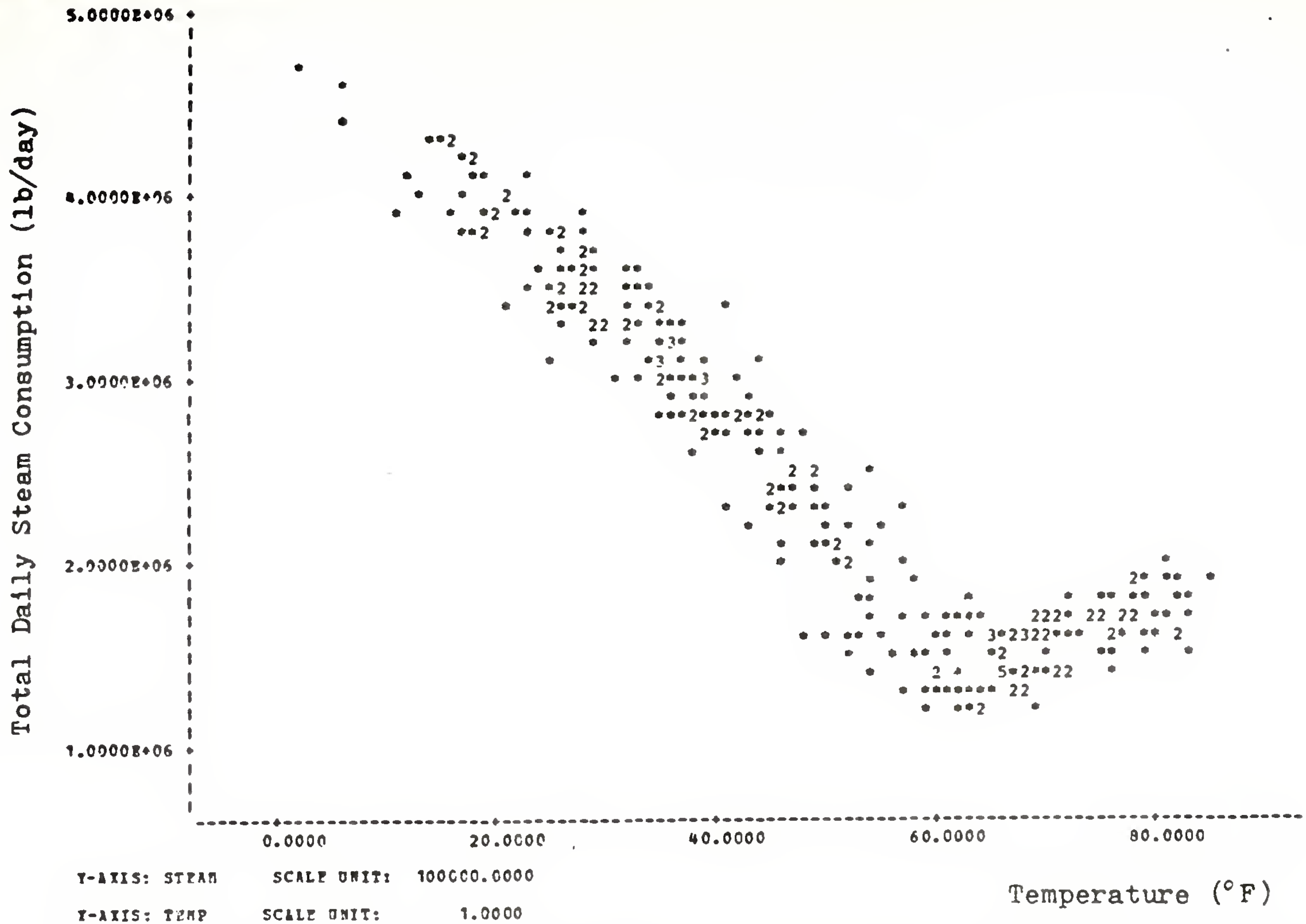


Figure 2.1 - MIT Weekday Steam Demand Versus Ambient Temperature (1/76 - 2/77) [11]

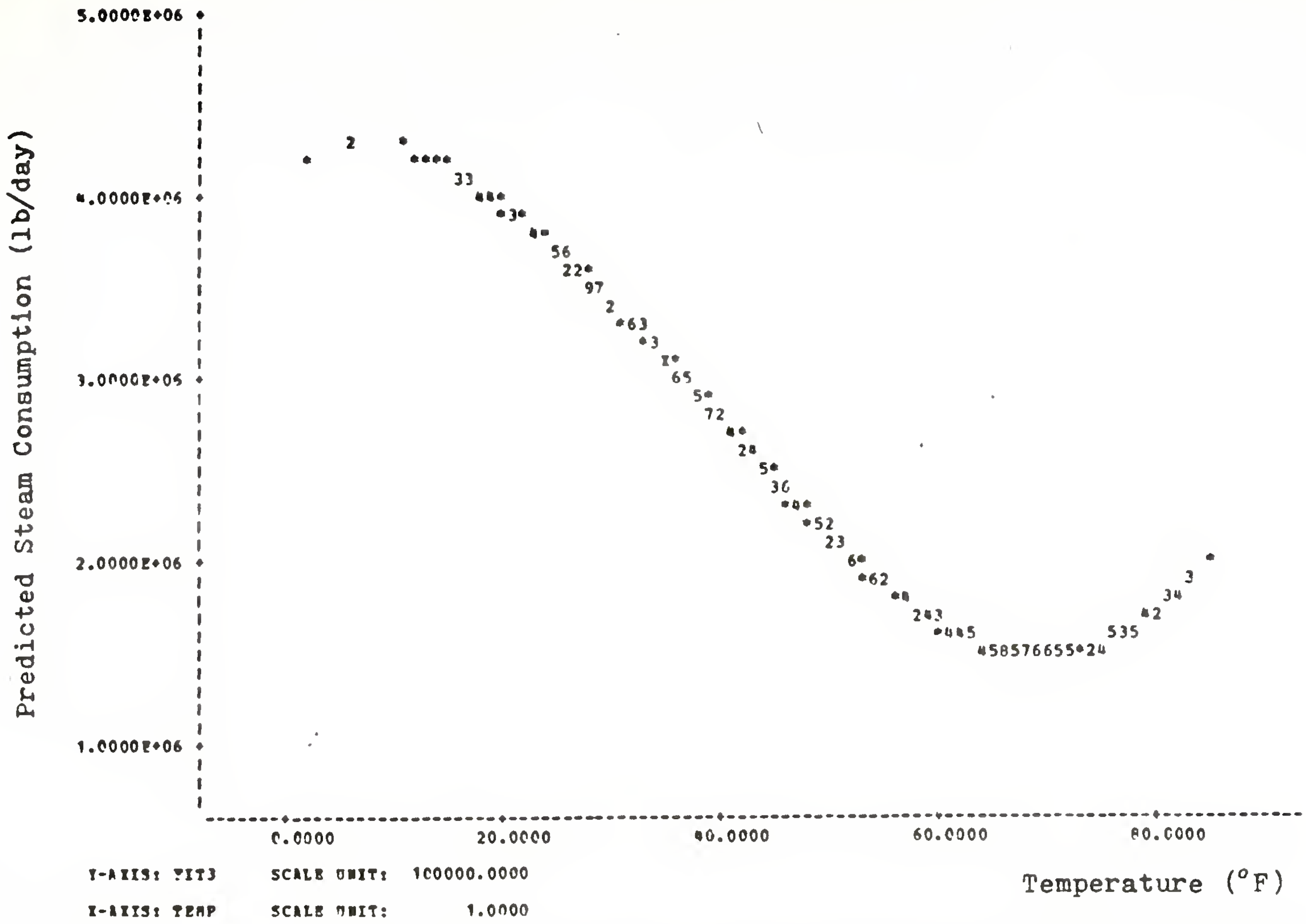


Figure 2.2 - Fitted Curve of Weekday Total Steam Demand Versus Temperature [11]

RESPONSE	MEAN	STD. DEV.
STEAM	2.4979E+06	930951.0625

CARRIER:	CONST.	X1	X2	X3
COEF.	4.1719E+06	32359.3867	-2588.0669	22.5004
S.E. COEF.		9523.0234	220.2660	1.5626
MEAN		48.4152	2736.0740	170237.4375
STD. DEV.		19.8336	1947.4434	161891.3125

MULTIPLE R SQUARED 0.9445

ANALYSIS OF VARIANCE TABLE

	SS	DF	MS	RMS
FIT	2.4066E+14	3	8.0220E+13	8.9565E+06
RESIDUAL	1.4141E+13	291	4.8593E+10	220438.0625
TOTAL	2.5480E+14	294		

	F	F PROB.
FIT	1650.8523	0.9961

REGRESSION MATRIX - ELEMENTS IN LOWER TRIANGLE GIVE INVERSE OF CORRELATION MATRIX

	X1	X2	X3
RESPONSE	-0.9255	-0.8656	-0.7932
X1	215.8312	0.9812	0.9449
X2	-479.4600	1113.2351	0.9896
X3	270.5137	-648.5669	387.1848

PLOT FIT3 VS TEMP;

Table 2.2 - Regression Statistics for Weekday Steam Analysis [11]

These regression statistics indicate the quality of the curve fit. The high R^2 value implies that temperature alone is an outstanding predictor of the daily total steam demand. The magnitude of the F statistics indicate that temperature is indeed a significant parameter in the regression analysis and that the variance in steam demand explained by the regression (temperature) is many times greater than the variance which is left unexplained. The only mismatch of any consequence between the data and the polynomial approximation predictions occurs for temperatures less than 6°F. The error is approximately 7% and is explained by the scarcity of data points in this temperature range.

The above procedure was used to determine the daily total steam demand. The hour by hour steam demands were determined based on seasonal patterns which were developed from the steam plant operating logs.

The hourly steam demand, as transcribed from the operating logs, was normalized with respect to the hourly average for that day. These normalized quantities were referred to as "hourly load factors", and they verified that seasonal daily profiles did exist for both weekdays and weekends/holidays.

Refinement of the hourly load factor data was accomplished with an IMSL library subroutine (LSFIT) to perform a least-squares regression analysis. Disparities between the fitted curves and the data were reduced to acceptable levels by adjusting the magnitude on some of the scale factors so as to more accurately reflect the seasonal trend. Each represents a composite profile inasmuch as it reflects a balance between polynomial approximation techniques and optimization efforts to ensure a minimum error sum of squares (highest R^2 value) between data and fit.

For any particular temperature day, the hourly distribution of steam demand may be predicted as follows:

a) Compute the daily total steam demand as a function of temperature.

b) Divide this daily total by 24 to obtain the average hourly demand.

c) Multiply this average hourly demand by the respective hourly load factor to determine the "predicted" steam load for that hour.

2.3.2 Electrical Load Profile Development

Unlike the steam demand, electrical power consumption at MIT was not a simple function of ambient parameters. The operation of lights and major ventilation equipment is

virtually independent of temperature, cloud cover and wind speed. It was true that during the warmer months a decided load increase could be observed - this reflected the wide spread use of fans and window type air conditioning units.

Graphs of daily total kilowatt load versus temperature were constructed for the weekdays and weekend/holidays. The data indicated that while daily total kilowatt load could not be reliably predicted on the basis of temperature alone, it was bracketed by specific upper and lower bounds as shown in figure 2.3 for the weekday data. Days with temperatures less than 60°F show essentially the same upper and lower bound, while these bounds tend upward for days with temperatures greater than 60°F. These distinct bounds suggested that a scheme could be devised to predict the daily total kilowatt load based on historical distribution patterns.

It was decided to assign total kilowatt loads to days using the same proportional distribution as that which characterized the sampling data. In this manner, a true simulation of the "typical" consumption patterns would be developed. These percentage distributions of kilowatt load were used to predict a spread of representative electrical consumption totals for any number of days, based on the data's bounds at that particular day's average ambient temperature.

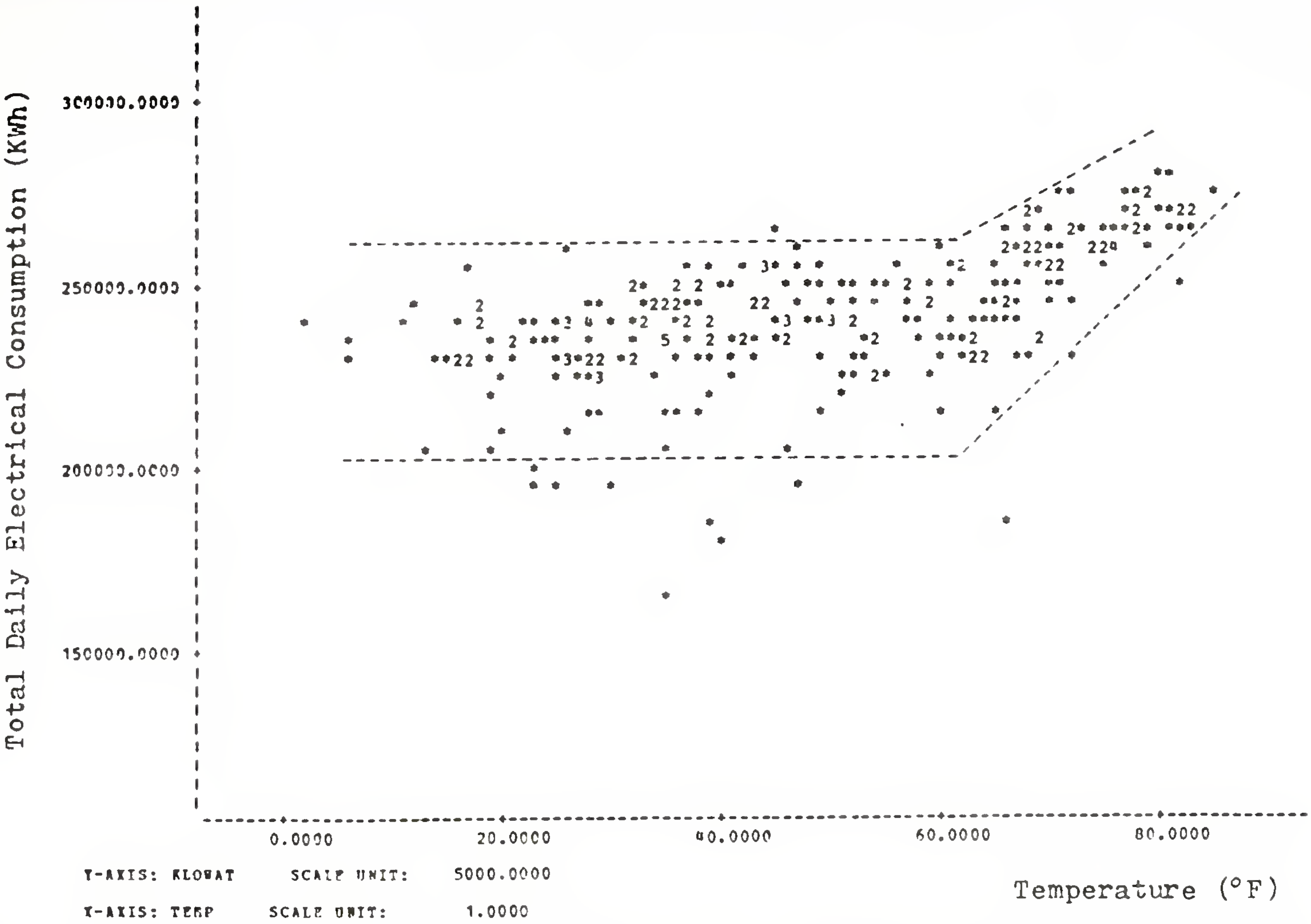


Figure 2.3 - MIT Weekday Electrical Demand Versus Ambient Temperature [11]

The hour by hour electrical demands were then determined based on patterns developed from MIT's electrical logs. Very little seasonal similarity existed except for the time of occurrence of the peak demand. Hourly kilowatt load factors were calculated in the same manner as the hourly steam demand load factors.

Refinement of these hourly load factor profiles was accomplished with the same IMSL library subroutine (LSFIT) which was utilized for the daily steam profiles. Groups of days which exhibited the same time of peak occurrence were input, and a least-squares regression analysis was performed. Minor adjustments to these polynomial approximations, similar to those for the steam profiles, reduced the disparities between the fitted curves and the data to acceptable levels.

For the purpose of electrical load simulation, a system of random load profile selection was employed in the same proportionate distribution reflected in the data sampling. In this manner, the various profiles were apportioned over all the days of the year.

2.3.3 Load Model Development for a Representative Year

A model year was created based on historical data of the average daily temperatures in the Cambridge, Massachusetts area. The data was obtained from the Boston Weather Bureau.

Because the daily steam load profiles are characteristic of specific seasons, it was necessary to determine an approximate dividing line for temperatures within each season. Four temperature bandwidths were constructed which reflect an approximate breakdown by season. The assignment of a specific temperature to days within any one season was made in accordance with the model year temperature distribution and this seasonal temperature breakdown.

The development of a typical year implies that 2/7 of the days are weekends while 5/7 are weekdays. Twelve holidays are also recognized for MIT employees during a normal year, as distinguished from the group of student holidays which do not include the entire MIT community. Inclusion of these twelve holidays yields a total of 116 days which exhibit weekend/holiday demand characteristics while 249 exhibit weekday characteristics. The assignment of specific temperatures to weekdays and weekend/holidays was then made.

The steam consumption for any day is a function only of outside ambient temperature. Assignments of daily total kilowatt demand were made in accordance with the percentage distributions derived from the historical data sample. This resulted in a proportionate distribution within

specific temperature ranges of the model year. The actual association of a daily total kilowatt demand with one particular temperature day was made randomly.

The steam demand daily profiles which were developed for each season were applied directly to weekdays and weekend/ holidays. Electrical load profiles were prescribed according to the frequency of occurrence in the sample year. Individual assignments were made randomly so as to achieve the correct proportionate distribution of profiles for each temperature band.

The accuracy of the load model predictions was validated through the use of subroutines which simulated the operation of the MIT Central Utility Plant boilers and the current electrical billing rate structure from Cambridge Electric with the use of 1976 actual weather data. The results of this simulation were most encouraging.

The computer model over predicted fuel consumption for the entire year by 1.4%. Six of the twelve months showed less than 0.1% difference between that which was actually consumed and that which was estimated. The greatest disparities were noted in the spring and fall seasons, presumably because of peculiarities associated with the shift from heating to air conditioning and back again.

The peak electrical demand predicted by the load model was 15,583 KW, compared to the most recent peak that year of 15,240 KW. The average cost of purchased electricity calculated by the computer program for the model year agreed almost perfectly with the cost figures available through the Physical Plant Office. Although the load model apportions the electrical power consumption differently by month (in accordance with temperature distribution), the net result in terms of total usage was very similar.

2.4 Summary of Load Profile Analysis

The preceding section summarizing the load profile analysis at MIT has been included to demonstrate that with very little difficulty a comprehensive analytical program can be developed to model a facilities thermal and electrical loads on an hour by hour basis for an entire year. It was demonstrated that an excellent correlation could be established between the thermal loads and a single independent variable--the outside ambient air temperature after correction for wind speed. The electrical loads were then correlated with the same outside ambient temperature in the same proportionate distribution reflected in the data sampling.

It is this hour by hour matching of the thermal and electrical loads which will determine the quantity of waste heat, which is a by-product of electrical power generation

which can be successfully utilized by a total energy system configuration. This degree of waste heat utilization will ultimately determine the thermodynamic attractiveness and economic success of the proposed installation.

Previous conceptual design studies for total energy systems at other universities and Naval Bases dealt primarily with total daily or monthly loads or with the daily peaks and averages.[2,7,8] These values are satisfactory for sizing equipment to satisfy the expected peak demands or for extrapolation to a higher level as in the case of the Booz-Allen and Hamilton Naval Base studies.[2]

However, maximum utilization of waste heat and eventual success of a total energy system installation requires that a detailed study of the thermal and electrical loads on an hourly basis be completed first. The results of this load analysis can then be used as guidance in the selection and analysis of candidate systems in the conceptual design and feasibility study for the project.

CHAPTER 3

ALTERNATIVE SYSTEM CONFIGURATIONS

The aspect of a heat recovery system feasibility analysis which is least subject to a systematic approach is the development of specific equipment configurations. It is these various plant configurations which must be ranked according to their economic and thermodynamic (measured in terms of fuel conservation) advantages in relation to a conventional system. A conventional system is defined as any typical energy system which uses commercial electrical power and generates steam or hot water in a central or self-contained energy plant. Air conditioning requirements may be met by chilled water generated in a central plant, or it may be decentralized in various buildings.

This chapter examines the various system configurations which are the most common and applicable to naval activities. The advantages and important or unique features of each are summarized, and the results of previous conceptual design studies are reviewed.

3.1 Peaking Systems

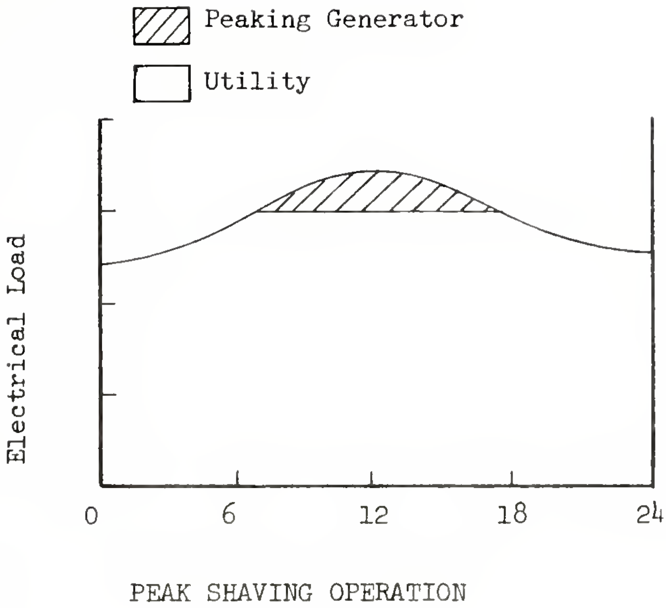
Peaking type electrical generation systems generally evolve from the test operation of standby or emergency power generators into operation on a regular basis. Their economic

advantage is realized in situations where the daytime loads are significantly higher than those at night. In this manner, a considerable savings is obtained from the demand charge portion of the electric bill. There must also be an agreement between the commercial utility and the activity which allows the on-site generation of electric power in this manner. There may or may not be additional back up service fees charged by the utility based on the size of the peaking generator.

Basically there are two methods of operating an electrical peaking system. These are shown in Figure 3-1. One method, known as peak shaving, is to begin operating at a certain pre-determined load, and then generate all of the electric power requirements above this level. In this manner, the commercial utility supplies a constant load, while the peak shaving generator supplies the variable load requirements above this level.

The second method is to begin operating at a certain pre-determined load, and then operate the peaking generator at full capacity until the load drops below that predetermined level. This method of full load operation has several advantages over the peak shaving method.

Specific fuel consumption of the peaking generator at the full load rating will be better than the off-design performance of the peak shaving operation.



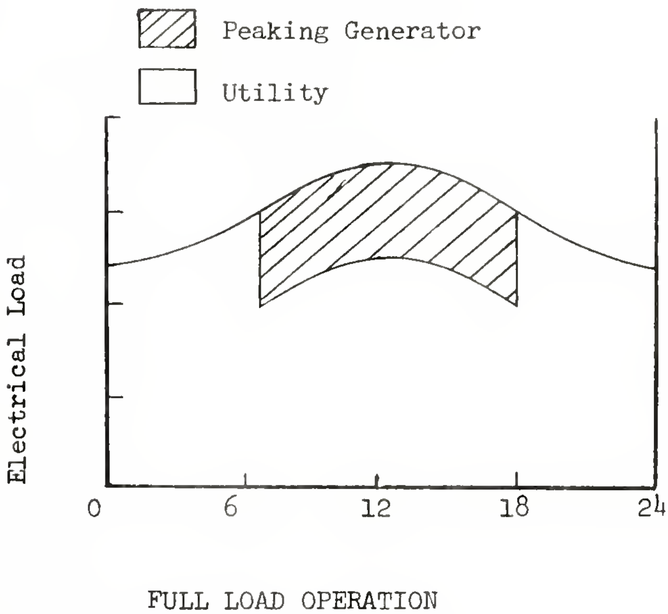


FIGURE 3-1 Methods of Operating an Electrical Generation Peaking System

Operation at full load rating will enable greater utilization of waste heat through exhaust heat recovery boilers and ancilliary heat exchangers than could be achieved at the off-design performance of the peak shaving unit.

Also, there may be problems with governor operation in controlling the variable load above a certain set point than with a generator which is fully loaded in parallel with the commercial grid.

3.2 Select Energy Systems [5,6,7,8]

A Select Energy System (SES) provides as much electricity as can be generated under the given thermal demands. This is generally 40 to 70 percent of the user's electrical peak demand requirements. The electrical power generation is deliberately limited to the capacity required to assure maximum utilization of the recovered waste heat from the prime movers to satisfy the coincidental thermal loads (heating, cooling and domestic hot water). It is these thermal demands which determine the magnitude of the on-site electrical power generation. Thermal demands over and above that which can be supplied from the prime mover are generally met with conventional boilers. Electrical demand above the generator capacity is purchased from the local commercial utility. Optimization of the select energy system performance

is accomplished by sizing the prime mover such that it is operated with a significant load factor throughout the year. This usually results in an overall system efficiency of 75% or greater.

The most significant feature affecting the installation of a select energy system is the contract agreement with, and the attitude of, the local commercial utility with regards to on-site electrical power generation. The economic attractiveness of a select energy system is dependent upon the basic electrical rate structure, and any back-up service fees which may be required. The select energy system generally has no reserve capacity, and the local utility is relied upon to supply not only the peak electrical loads, but also the entire electrical load in the event of a casualty or major maintenance requirement for the on-site generator.

If the local utility should become overloaded or fail at times, the select energy system would not be able to provide the peak user loads, and loads may have to be shed. However, the select energy generation system is generally larger than a conventional standby or emergency generator and is beneficial in this respect.

A select energy system requires less capital investment than a total energy system because of the reduced equipment costs which are required for reserve capacity and reliability. Select energy installations should be considered for facilities where an uninterruptable load is not a critical item. At facilities with a critical load, a select energy system should be considered if shedding of the non-critical load can be accomplished. In this case the capacity of the generators should be large enough to satisfy the critical load, which will eliminate the need for idle emergency generators.

In selective energy systems, recovery of equipment capital cost may be improved by the use of thermal heat storage devices to provide a more uniform heat recovery profile for the engines. In this manner, fewer engines may be needed and higher engine utilization (increased load factor) may be achieved. Thermal heat storage may also allow efficient utilization of the engines for peak shaving without the need for a simultaneous thermal load.

3.3 Total Energy Systems [5,6,7,8]

A Total Energy System (TES) is an on-site electrical power generating system which is designed and arranged to obtain the maximum use of the input fuel energy through the

utilization of waste heat for space heating, space cooling and domestic hot water heating. A total energy system satisfies all of the electrical and thermal demand loads of the facility. Thermal demands over and above that which can be supplied from the electrical power generation are generally met with conventional boilers.

A total energy system is completely independent of the local commercial utility. Therefore, there must be sufficient on-site back-up generating capacity to meet the facilities electrical load demands during both planned and unplanned equipment ontages. The determination of the exact quantity of extra equipment required for each system design must be based on the results of a detailed reliability and availability analysis of each system. This reliability analysis of the system design is one of the most important design steps which can impact the successful application of a total energy system installation.

Proper system design from the reliability aspect will insure adequate reserve capacity for operation independent of the commercial utility grid. It is this feature which makes total energy systems attractive options for facilities with critical electrical loads such as communications and computer equipment. This independence will insure continued operation should the local utilities become overloaded or fail at times.

The extra equipment required for this reserve capacity results in a high initial capital investment for a total energy system. However, because the total energy system is independent of the utility grid, there are no annual service charges or back-up fees as with a select energy system. A detailed trade-off study must be conducted for each particular installation in order to resolve these points.

Similar to select energy systems, the recovery of equipment capital cost for total energy systems may be improved by the use of thermal heat storage devices to provide a more uniform heat recovery profile for the engines. The system's energy efficiency may be improved by storing waste heat which is produced during periods of high mechanical or electrical load, and then releasing it when engine heat output is low. It should be noted that this heat storage concept is useful only if there are periods when the systems thermal demand significantly exceeds the heat output of the engines, so that the stored thermal energy can then be used.

The capital cost may also be reduced by the use of gas turbines for peaking or reserve capacity in conjunction with base loaded steam or reciprocating engine generators.[5] If the peaks are of short duration, the overall reduction of the system's energy efficiency may be small.

3.4 Review of Alternative System Configuration Designs

All of the system configurations described in the preceding sections of this chapter were analyzed in detail during the conceptual design of a total energy system for MIT, references [9,10]. The results of this system analysis are summarized in this section to show the value of the important or unique features of the various alternative configurations. It should be noted again that systems such as these are very site-specific. They are designed to meet specific operational load profiles and are subject to specific local regulations regarding on-site electrical generation, type of fuel which may be used and other environmental impacts, etc. Therefore, the results of this analysis will not specifically be applicable to other installations and cannot be easily extrapolated to a higher level through trend analysis methodologies.

The first system configurations which were analyzed in the design study were termed Dependent Total Energy Systems because while each one supplied all of MIT's electrical and thermal energy requirements, they depended on the public utility (Cambridge Electric) for back up electrical service during both planned and unplanned equipment outages. In essence, these were select energy systems which were

designed to generate all of MIT's electrical demand requirements rather than only the portion which would satisfy the coincidental thermal steam demand requirements only. However, there was little or no redundancy for generating electricity, and all maintenance functions would be performed on the equipment during the appropriate times of the day, on weekends, or during the seasons when the electrical demand is relatively low and individual generators could be secured. The existing ties with the utility grid were maintained for emergency use only. The annual service charge for maintaining this tie under the existing contract was approximately $432,000. This service charge is based on the maximum existing demand which would have to be supplied by the utility in the event of a systems failure. This service charge was also treated as another annual operating expense for each system.

Four individual plant configurations using three types of prime movers were analyzed: a diesel engine plant, two gas turbine plants and an extraction steam turbine plant. A straightforward thermodynamic and system economic analysis was made utilizing the MIT load profile model described in the previous chapter. The results of these analyses are shown in Tables 3.1 and 3.2

TABLE 7.1 Summary of Energy Consumption and Savings for Dependent Total Energy Systems

	Base Case-Existing Operation	Diesel Engine System	Gas Turbine 3 Generator System	Gas Turbine 2 Generator System	Extraction Steam Turbine System
ELECTRICITY:					
Electricity consumed - 10^6KWh	82.654	82.654	82.654	82.654	82.654
Electricity Generated On-Site 10^6KWh	0	82.654	82.654	82.654	82.654
Electricity Purchased - 10^6KWh	82.654	0	0	0	0
Electricity On-Site %	0	100	100	100	100
FUEL:					
Fuel Type #2 or #6	#6	#6	#2/#6	#2/#6	#6
On-Site Fuel Fired - 10^9Btu	1004.4	1601.9	1850.3	1902.7	1865.0
10^6Gals.	6.934	11.058	9.869/2.796	10.188/2.835	12.875
Central Station Fuel - 10^9Btu	826.5	0	0	0	0
(Equivalent) 10^6Gals	5.706	0	0	0	0
Total Fuel Fired - 10^9Btu	1830.9	1601.9	1850.3	1902.7	1865.0
10^6Gals	12.640	11.058	9.869/2.796	10.188/2.835	12.875
SUMMARY:					
(1)Overall Energy Demand 10^6KWh	331.304	331.304	331.304	331.304	331.304
Energy Savings Over Base Case 10^9Btu	-	229.06	-19.4	-71.8	-34.1
% Base Case Fuel Consumption	100	87.5	101.1	103.9	101.9
(2)Central Station Ann-Heat Rate Btu/KWh	10,000				
On-Site Ann Heat Rate Btu/KWh	4040	4835	5585	5743	5629
Combined Heat Rate Btu/KWh	5527	4835	5585	5743	5629

(1) Institutes thermal and electrical consumption.

(2) This figure of 10,000 Btu/KWh represents a conservative estimate of the average annual heat rate for Cambridge Electric and the New England Power (Yankee) Grid System.

TABLE 3.1 - Select Energy System Energy Consumption and Savings.[9]

TABLE 7.3 Summary of Life Cycle Cost Analysis for Dependent Total Energy Systems

	Base Case-Existing Operation	Diesel Engine System	Gas Turbine 3 Generator System	Gas Turbine 2 Generator System	Extraction Steam Turbine System
Annual Operating Cost	$5,410,500	$4,514,500	$5,607,700	$5,767,000	$5,357,000
Net Annual Savings		896,000	-197,200	-356,500	53,000
Initial Investment		6,902,000	8,648,000	7,584,000	12,800,000
Internal Rate of Return		11.51%	(1)	(1)	-17.07%
Net Present Value Analysis					
6% Net Present Value		3,363,600	(1)	(1)	-12,192,000
Benefit Cost Ratio		1.49			0.047
8% NPV		1,885,200			-12,280,000
B/C		1.27			0.040
10% NPV		717,700			-12,349,000
B/C		1.10			0.035
12% NPV		-216,900			-12,404,000
B/C		0.97			0.031

(1) Economic indicators not calculated due to fact that net annual savings are negative.

TABLE 3.2 - Select Energy System Life Cycle Cost Analysis.[9]

A reliability and availability analysis for these dependent total energy systems was then developed to determine the probable frequency that each system would utilize this dependent back up electrical service. The analysis was based on equipment data contained in the "Report on Equipment Availability for the Ten-Year Period, 1965-1974" compiled by the Edison Electric Institute.[14] The following table summarizes this reliability and availability analysis for the dependent total energy systems.

	Reliability (1 year)	Availability (1 year)
Steam Plant	55.2%	91.3%
Diesel Plant	71.7%	99.5%
Gas Turbine Plant	44.5%	97.0%

This reliability analysis was then used to determine the number of major system components which would justify a total energy system independent of the public utility grid.

The system reliabilities for 3 engine and 4 engine systems were calculated for periods of one year and one month in order to determine the number of diesel or gas turbine generators required for satisfactory independent operation. The one month calculation is representative of a

typical period for engine overhaul or major repair. The assumption was made that two engines could adequately satisfy the Institute's electrical load, and that the system failed anytime the load could not be entirely met. The results of this analysis are shown in the table below.

	Reliability for one Year	Reliability for one month (30 days)
Three Diesels, Two Required for Load	71.8%	97.4%
Four Diesels, Two Required for Load	98.6%	99.9%
Three Gas Turbines, Two Required for Load	44.5%	93.9%
Four Gas Turbines, Two Required for Load	94.4%	99.6%

For the Institute to operate independent of the utility in a reliable manner, it was felt that the four engine systems did not provide sufficient redundnacy. Therefore, a system of five engines was recommended to provide sufficient redundancy for the system. The five engine system has a reliability of 99.9+% for one year and 99.9+% for one month with one engine down for overhaul. The five engine system also provides sufficient redundancy to insure reliable operation in the event of a catastrophic failure to one engine which required more than one month for repair.

A completely redundant extraction steam turbine plant was also analyzed. This system was shown to have a reliability of 99.9% for a one year period and 94.7% if one turbine generator and one boiler are out-of-service for a 30 day maintenance period.

An extraction steam turbine plant utilizing three diesel engine generators for back-up reserve capacity was then examined as a less expensive alternative to the completely redundant steam plant. The reliability of this system is 99.9+% for a one year period and 97.4% for a one month period when the boilers and turbine are out of service for maintenance.

A summary of the life cycle cost analysis for each of these four independent total energy systems is shown in Table 3.3. It is interesting to note in comparing Tables 3.2 and 3.3 that the dependent total energy systems, with the annual service charges for back-up electrical support from the utility, are more economically attractive than the completely independent total energy systems. The increased capital cost of the additional equipment required for the total energy systems was not offset, in this particular case, by the elimination of the back-up electrical service fee and subsequent reduced annual operating cost.

TABLE 9.2 Summary of Life Cycle Cost Analysis for Independent Total Energy Systems

	Base Case-Existing Operation	Diesel Engine System	Gas Turbine System	Steam System Redundant	Steam System Diesel Back-up
Annual Operating Cost	$5,410,500	$4,132,500	$5,225,700	$15,025,000	$4,420,000
Net Annual Savings		1,278,000	184,800	385,000	990,500
Initial Investment		11,018,000	13,928,000	21,400,000	19,000,000
Internal Rate of Return		9.82%	-10.27%	-8.23%	0.41%
Net Present Value Analysis					
6% Net Present Value		3,640,500	-11,808,500	-16,984,000	-7,611,400
Benefit Cost Ratio		1.33	0.15	0.21	0.60
8% NPV		1,529,500	-12,113,600	-17,670,000	-9,247,500
B/C		1.14	0.13	0.18	0.51
10% NPV		-137,700	-12,354,800	-18,122,000	-10,539,500
B/C		0.99	0.11	0.15	0.44
12% NPV		-1,472,500	-12,547,600	-18,524,000	-11,573,800
B/C		0.87	0.10	0.13	0.39

TABLE 3.3 - Total Energy System Life Cycle Cost Analysis.[9]

Peaking type electrical generation systems were then investigated to determine the annual savings obtainable with a substantially smaller capital investment. MIT operated a 900 KW emergency diesel generator set as a peak shaving unit in order to reduce the peak electric demand purchased from the local utility. This analysis investigated the extension of this peaking method of operation with the use of larger diesel engine and gas turbine generators which also utilized waste heat recovery boilers.

Operation was such that the peaking generator was started when the electrical load reached a predetermined level, and was then run at full capacity until the load dropped below that level. Determination of this start point was made based on the consideration of the number of hours per year that the engine would be run, and the subsequent time which would remain available to complete the required maintenance functions on the engines.

One diesel engine and one gas turbine system were analyzed in detail. The results of this analysis are shown in Tables 3.4 and 3.5. The economic indicators of Internal Rate of Return and Benefit Cost Ratio are considerably higher for the peaking systems than those for either of the total energy systems. However, the Net Present Value of the peaking systems are much lower, and the fuel energy savings

TABLE 10.1 Summary of Energy Consumption and Savings for Peaking Type Systems

	Base Case- Existing Operation	Diesel Engine System	Gas Turbine System
ELECTRICITY:			
Electricity Consumed - 10^6 KWh	82.654	82.654	82.654
Electricity Generated - 10^6 KWh	0	24,297	24.297
Electricity Purchased - 10^6 KWh	82.654	58.357	58.357
Electricity Generated - %	0	29	29
FUEL:			
Fuel Type #2 or #6	#6	#6	#2/#6
On-Site Fuel Fired - 10^9 Btu	1004.4	1206.2	1254.8
10^6 Gallons	6.934	8.329	3.472/4.988
Central Station Fuel - 10^9 Btu	826.5	583.6	583.6
(Equivalent) 10^6 Gallons	5.706	4.029	
Total Fuel Fired - 10^9 Btu	1831.0	1789.8	1838.4
10^6 Gallons	12.640	12.358	3.472/9.017
SUMMARY:			
(1)Overall Energy Demand - 10^6 KWh	331.304	331.304	331.304
Energy Savings Over Base Case - 10^9 Btu		41.2	-7.4
% Base Case Fuel Consumption	100	97.7	100.4
(2)Central Station Annual Heat Rate - Btu/KWh	10,000	10,000	10,000
On-Site Annual Heat Rate Btu/KWh	4040	4419	4597
Combined Heat Rate Btu/KWh	5527	5402	5549

(1)Institutes thermal and electrical consumption.
(2)This figure of 10,000 Btu/KWh represents a conservative estimate of the average annual heat rate for Cambridge Electric and the New England Power (Yankee) grid system.

TABLE 3.4 - Full Load Peaking System Energy Consumption and Savings.[9]

TABLE 10.3 Summary of Life Cycle Cost Analysis for Peaking Type Systems

	Base Case- Existing Operation	Diesel Engine Peaking System	Gas Turbine Peaking System
Annual Operating Cost	$ 5,410,500	$ 5,026,600	$ 5,102,300
Net Annual Savings		383,900	308,200
Initial Investment		2,301,000	2,883,000
Internal Rate of Return		15.8%	8.66%
Net Present Value Analysis			
6% Net Present Value		2,102,800	652,100
Benefit Cost Ratio		1.91	1.23
8% NPV		1,468,600	143,200
B/C		1.64	1.05
10% NPV		967,800	-258,800
B/C		1.42	0.91
12% NPV		566.900	-580,700
B/C		1.25	0.80

TABLE 3.5 - Full Load Peaking System Life Cycle Cost Analysis.[9]

are also substantially less. No additional back-up service fee was incorporated in the economic analysis of these peaking systems because it is simply an extension of MIT's present operation to a larger scale, which is looked upon favorably by the local utility.

The final systems investigated in this design study were select energy systems. A diesel engine generator and several extraction steam turbine generators were analyzed for installation as baseload power plants. They were termed baseload plants in this study because they were designed to be operated continuously at their rated electrical capacity, which corresponds approximately with the systems minimum electrical load demands. Operation in this manner insured full utilization of the recoverable waste heat from each system.

A reliability and availability analysis was performed to determine the number of boilers or engines which would be required to permit continuous operation of the system. The systems were assumed to have failed anytime that they could not provide their rated capacity of electrical power. This would force MIT to purchase all of its electrical power requirements from the local utility, thus increasing the billing demand level. The table below summarizes the reliability and availability analysis of the select energy systems (base load and dependent total energy).

	Reliability (For 1 Year)	Availability (For 1 Year)
Base Load Steam Plant (1 Boiler, 1 Turbine Generator)	4.71%	85.58%
Base Load Diesel Plant (2-Generators)	71.7%	99.75%
Diesel Engine Dependent Total Energy System	71.7%	99.5%
Steam Turbine Dependent Total Energy System (2 Boilers, 1 Turbine Generator)	55.2%	91.3%

The results of the energy consumption and life cycle cost analysis of these plants is presented in Tables 3.6 and 3.7. No additional back-up service fee was incorporated in the economic analysis of these base load systems because of the redundancy and reserve capacity incorporated into each based on the system reliability analyses. Recent studies at two universities [7,8] also indicated that their respective utility companies did not object to baseload plant operations in the form of select energy systems.

TABLE 4.3 Summary of Energy Consumption and Savings

	Base Case Existing System	6MW SAE Turbine Base Load System	8MW SAE Turbine Base Load System	Base Load Diesel 2-Generator System	Diesel Engine Dependent T.E.S.
ELECTRICITY:					
Electricity Consumed - 10^6 KWH	82.654	82.654	82.654	82.654	82.654
Electricity Generated - 10^6 KWH	0	51.831	67.430	59.787	82.654
Electricity Purchased - 10^6 KWH	82.654	30.823	15.224	22.867	0
Electricity Generated - %	0	62.7	81.6	72.3	100
FUEL:					
Fuel Type: #2 or #6	#6	#6	#6	#6	#6
On-Site Fuel Fired - 10^9 Btu	1004.4	1381.9	1581.8	1415.2	1601.9
10^6 Gals	6.934	9.540	10.920	9.770	11.058
Central Station Fuel - 10^9 Btu	826.5	308.2	152.3	228.7	0
10^6 Gals	5.706	2.128	1.051	1.579	0
Total Fuel Fired - 10^9 Btu	1831.0	1690.1	1734.1	1643.9	1601.9
10^6 Gals	12.640	11.668	11.971	11.349	11.058
SUMMARY:					
(1) Overall Energy Demand - 10^6 KWH	331.304	331.304	331.304	331.304	331.304
Energy Savings Over Base Case-10^9 Btu	-	140.9	96.9	187.1	229.06
% Base Case Fuel Consumption	100	92.3	94.7	89.8	87.5
(2) Central Station Ann-Heat Rate - Btu/KWH	10,000	10,000	10,000	10,000	10,000
On-Site Ann Heat Rate Btu/KWH	4040	4599	5004	4588	4835
Combined Ann Heat Rate Btu/KWH	5527	5101	5234	4962	4835

(1) Institutes thermal and electrical consumption.
(2) This figure of 10,000 Btu/KWH represents a conservative estimate of the average annual heat rate for Cambridge Electric and the New England Power (Yankee) grid system.

TABLE 3.6 - Select Energy (Baseload) Systems Energy Consumption and Savings.[10]

TABLE 4.2 Summary of Life Cycle Cost Analysis

	Base Case Existing Operation	6MW SAE Turbine Base Load System	8MW SAE Turbine Base Load System	Base Load Diesel 2-GENERATOR System	Diesel Engine Dependent T.E.S.
Annual Operating Cost	$ 5,410,000	$ 4,820,000	$ 4,763,000	$ 4,516,100	$ 4,514,500
Net Annual Savings		590,500	647,500	894,400	896,000
Initial Investment		8,500,000	8,900,000	4,602,000	6,902,000
Internal Rate of Return		3.36%	3.87%	18.82%	11.51%
Net Present Value Analysis					
6% NPV		-1,727,000	-1,473,000	5,657,000	3,363,600
B/C		0.80	0.83	2.23	1.49
8% NPV		-2,702,000	-2,543,000	4,179,000	1,885,200
B/C		0.68	0.71	1.91	1.27
10% NPV		-3,472,000	-3,387,000	3,013,000	717,700
B/C		0.59	0.62	1.65	1.10
12% NPV		-4,089,000	-4,063,000	2,078,000	- 216,900
B/C		0.52	0.54	1.45	0.97

TABLE 3.7 - Select Energy (Baseload) Systems Life Cycle Cost Analysis.[10]

3.5 Summary of Alternative System Configurations

The preceding section summarizing the systems analysis of the conceptual design for a total energy system at MIT has been included to demonstrate the relative advantages of each heat recovery system configuration. It is only an example of an orderly and systematic approach to the development of specific equipment configurations and feasibility analysis of heat recovery systems.

The reliability and availability analysis was the basic guideline utilized in justifying the number of major system components required in either a total energy system or a select energy system designed for continuous operation.

Fuel consumption and cost figures were obtained for each system configuration through the application of the load profiles and model year described in Chapter 2. It was this hour by hour matching of the thermal and electrical demand loads with those of each system which determined the exact quantity of recoverable waste heat which could be successfully utilized in each case. This served to increase the accuracy of the operational cost estimates for fuel and purchased electricity. However, the basic service charges and additional back-up service fees must be determined for each individual installation through negotiation with the local commercial utility.

CHAPTER 4

STEAM TURBINE GENERATORS

Steam turbines are generally utilized as generator prime movers only in very large plants, whether or not they are configured as total energy systems. The reason for this is the very extensive investment in both capital and space which is required to build a steam plant of sufficient pressure and capacity to operate efficiently and reliably. The advantage of steam plants is their greater system efficiency and cost advantage when they are installed in large capacities.

Another significant advantage of steam plants is the flexibility afforded in the types of fuel which may be utilized. In addition to conventional fossil fuel oils and natural gas, boilers may be selected with the capability of efficiently burning coal, wood chips or other solid wastes. This is an important design feature of the steam plant in view of the Federal government's present plans of enforcing a shift to coal as the primary fuel for electric power generation and industrial processes.

4.1 Steam Turbine Configurations

A number of different turbine configurations may be used as generator prime movers. The three most common types of turbines utilized in total energy system configurations are backpressure, extraction and automatic variable extraction.

Backpressure turbines are non-condensing turbines which exhaust directly into the user's process steam line. These are utilized extensively for industrial process applications.

Extraction turbines are condensing turbines which have fixed ports for bleeding steam out of the turbine between certain stages. Several extraction points at various pressures may be operated simultaneously.

Automatic variable extraction turbines are capable of efficiently extracting a significantly large fraction of their throughput steam. The governor control system allows the ratio of extracted steam to steam exhausted to the condenser to be varied automatically. This allows the variation of the thermal steam energy/electrical energy ratio of the turbine generator to follow exactly the fluctuations of the user's load requirement.

The design and application of heat recovery systems utilizing steam turbine generators is quite different from the design of heat recovery systems with reciprocating engine

or gas turbine generators. Within the category of steam turbine configurations described above, there are significant differences between the condensing and non-condensing systems.

In general, condensing steam from a turbine prime mover is a waste of energy because the latent heat of condensation is discarded. Therefore, the most efficient steam turbine heat recovery systems generally utilize backpressure turbines where all of the steam is exhausted into the user's process steam system. In this manner, all of the sensible and latent heat can be recovered and utilized.

The backpressure turbine generator systems also have a definite cost advantage over condensing turbines. The condenser, cooling tower arrangement, piping system and pump installation account for between 8 and 11 percent of the initial cost of a single automatic extraction turbine generator system.[9,10,15] The annual maintenance and repair costs for this cooling equipment are also eliminated with a backpressure turbine.

However, the major disadvantage of the backpressure turbines with respect to condensing turbines is that the ratio of thermal steam energy output to mechanical or electrical energy output is generally high. The ratio can be reduced somewhat by utilizing higher inlet steam pressures

or lower exhaust or extraction pressures to increase the electrical output. This in turn may require the use of higher pressure boilers which may be practical only in large installations.

A backpressure steam turbine arrangement should be considered when the thermal steam load is continuously high compared with the electrical load. Because this thermal/electric ratio of the backpressure turbines is constant, they may be better suited for select energy systems where they are operated in parallel with the local utility grid and only supply a portion of the facilities electrical power requirements.

An automatic extraction turbine is required for a total energy system configuration where the facilities' thermal and electrical loads vary independent of each other. The turbines control system will automatically balance the thermal and electrical load requirements, and also minimize the amount of steam which must be condensed, with subsequent minimum loss of recoverable waste heat. The thermal/electric ratios and system efficiencies which are achievable with various turbine generator configurations are detailed in the following sections.

4.2 Steam Plant Design Parameters

Two important pieces of information which are desired for analytical purposes are the overall system energy efficiency and the thermal/electric ratio.

The thermal/electric ratio is simply the ratio of the thermal steam load demand of the system to the electric load demand of the system, in common units. The electric load demand is that hourly electric demand of the system which is supplied by the on-site generator.

The steam load demand has been defined for this analysis to be the mass flow of steam in lbm/hr required by the system, operating across an enthalpy drop between the process steam requirement (desired pressure and temperature) and the feedwater entering the boiler economizer. A common point had to be selected in the system where all of the returns and drains and make-up feed have been joined together and brought to a common pressure, temperature and energy level. For the systems which do not incorporate any high pressure feed heaters, this common point is the outlet of the deaerating feed tank. For systems which include high pressure feed heaters, the duty of these heaters must be included as part of the steam load, because their motivating steam is taken from the cycle and is an additional load on the system.

The thermal/electric ratio (T/E) is obtained by converting the steam load, as defined above, into megawatts and then dividing by the electrical load, also in megawatts.

The overall system efficiency (or energy efficiency) has been defined to be the ratio of the system energy outputs (or total load on the system) to the system inputs, again in common units. The load on the system is the sum of the hourly electrical and steam loads, as defined above. The energy inputs to the system are considered here only to be the energy contained in the fuel required for the boilers.

The boiler steam conditions and the pressure of the facilities steam distribution system must be determined at the beginning of the conceptual design. Industrial power plant turbine throttle pressures range between 600 and 1450 psig in current practice.[16] Steam pressures greater than approximately 1450 psig require a significant step increase in capital cost for both the turbines and the boilers. The four conventional turbine throttle conditions commonly available are:

600 psig, 750°F

850 psig, 825°F

1250 psig, 900°F

1450 psig, 950°F

The steam temperatures were selected so that the temperature of the turbine's exhaust or extraction steam would be essentially constant, regardless of the throttle pressure. This is illustrated on the simplified Mollier diagram shown in figure 4-1. The shaded area represents steam expanding through a typical industrial turbine at 78 percent efficiency. It can be seen that the steam exhausted or extracted at 50 psig would contain approximately 30°F of superheat for all four turbine throttle conditions examined.

The turbine's exhaust or extraction steam pressure should be selected as low as possible, consistent with the facilities' ambient requirements. Those requirements are generally set as a maximum pressure compatible with the space or domestic hot water heating equipment, or a minimum pressure to insure adequate flow and circulation to the extreme points of the distribution system.

In general, the lowest acceptable steam pressure for the facilities' thermal system will be the most effective in terms of the overall system energy efficiency. Extraction at lower pressures results in a smaller increment of turbine throttle flow over the non-extraction steam rate.

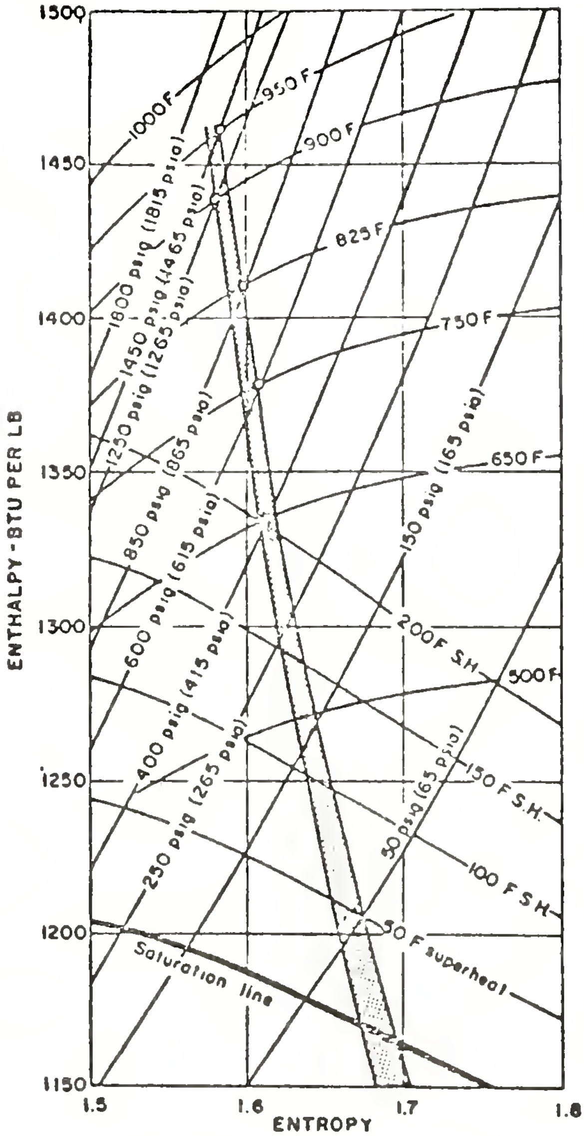


FIGURE 4.1 - Simplified Mollier Diagram Illustrating Turbine Throttle Conditions.[16]

It is most convenient to use the Replacement Factors, (RF), to determine this incremental throttle steam flow when operating with automatic extraction. The Replacement Factor is defined as that fraction of the extraction steam that must be added at the throttle to maintain the rated shaft power output when operating extracting. Figure 4.2 illustrates the replacement factor and explains how it is determined.[17] For example, given a steam turbine generator with throttle conditions of 850 psig, 900°FTT, exhausting at 3" HgA with an efficiency of 75%, the replacement factors for extractions at 200, 100 and 50 psig are:

$$RF_{200} = \frac{h_{200}-h_w}{h_o - h_w} = \frac{1346-1061}{1455-1061} = 0.723$$

$$RF_{100} = \frac{h_{100}-h_w}{h_o - h_w} = \frac{1299-1061}{1455-1061} = 0.604$$

$$RF_{50} = \frac{h_{50}-h_w}{h_o - h_w} = \frac{1258-1061}{1455-1061} = 0.500$$

This example illustrates how extraction at a lower pressure results in a lower increment of throttle steam flow required to maintain rated power.

Figure 4.3 illustrates the increase in energy efficiency which is obtainable for any given thermal demand by utilizing extraction steam at lower pressures. This

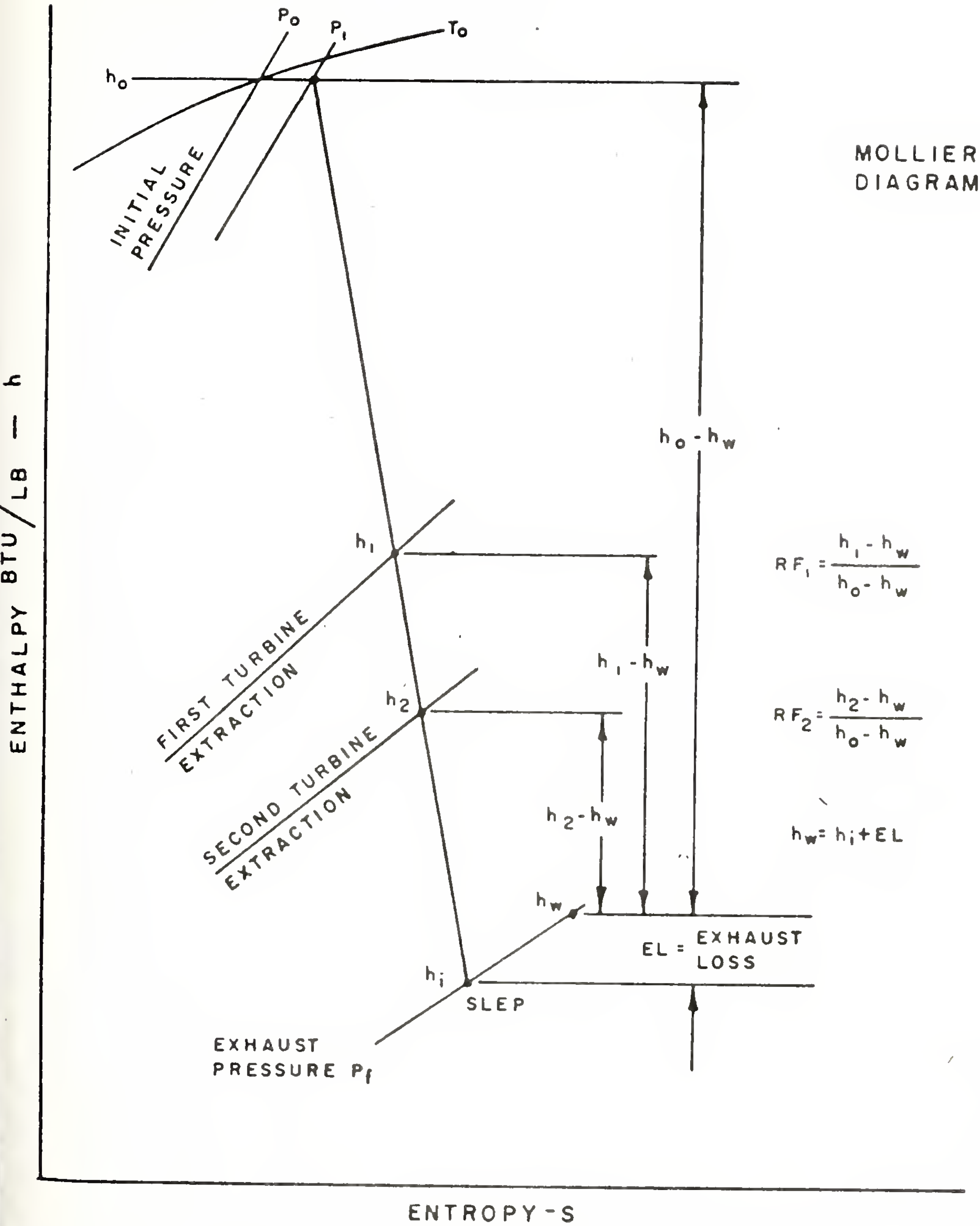


FIGURE 4.2 - Simplified Mollier Diagram Illustrating the Replacement Factor (RF).[17]

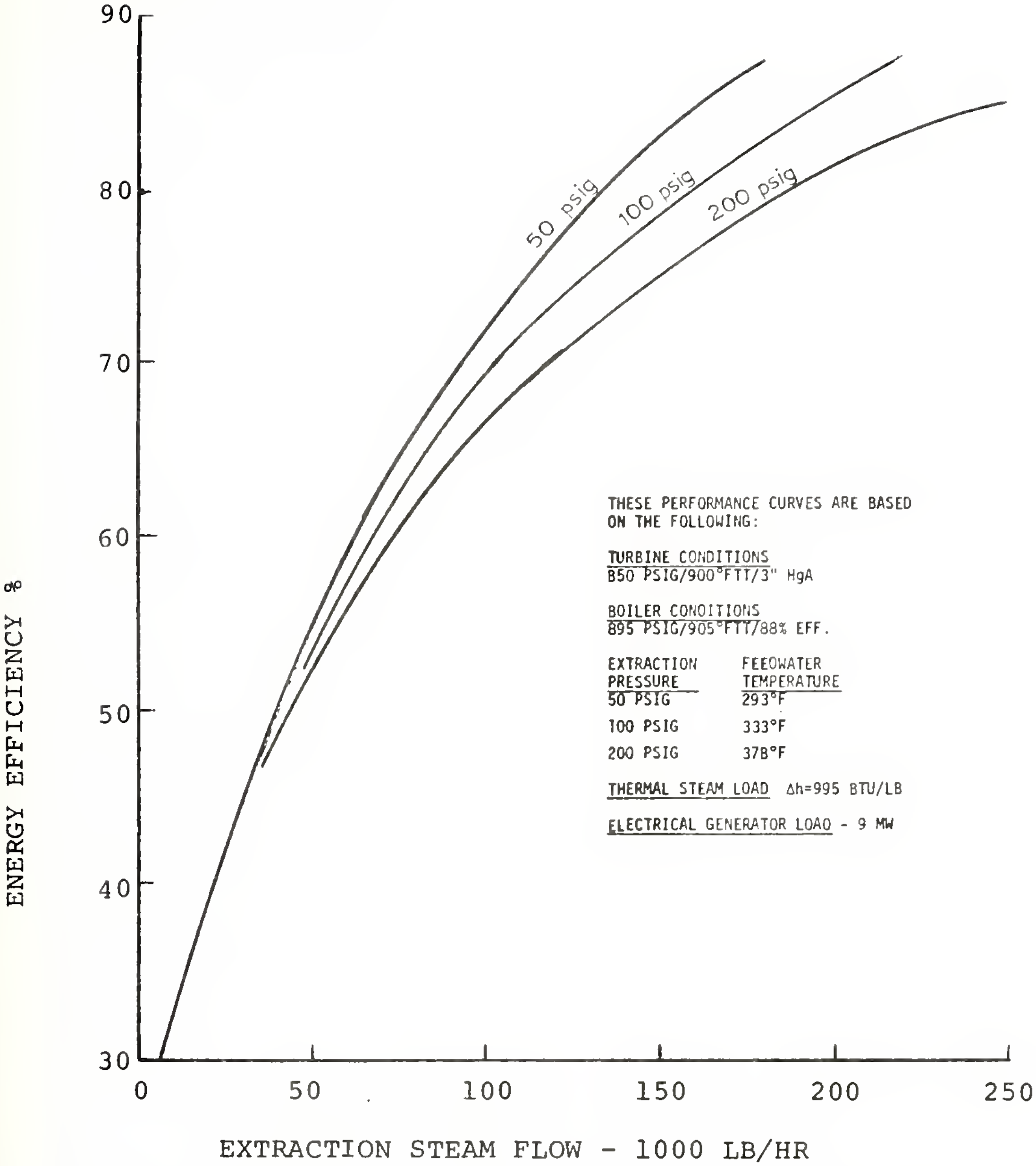


FIGURE 4.3 - Illustration of Increased Energy Efficiency Obtainable with Lower Extraction Steam Pressure.

example is based on a steam turbine generator with the same parameters described above, supplying 9 MW of electric power and a boiler efficiency of 88%. The enthalpy drop for the thermal steam load demand is 995 BTU/LB for each extraction pressure. For a steam load demand of 150,000 LB/HR, an increase of approximately 9 percent in the overall system energy efficiency may be realized by utilizing steam extracted at 50 psig rather than 200 psig. In this case, 150,000 LB/HR represents a thermal load of approximately 43.7 MW and a thermal/electric ratio of 4.9.

These same parameters for backpressure turbine generators with the same throttle conditions, supplying 9 MW of electric power and exhausting at 50, 100 and 200 psig are shown below in table 4.1.

TABLE 4.1 - System Parameters for Backpressure Turbine Generators Supplying 9 MW Electric Power

Exhaust Pressure - psig	50	100	200
Steam Flow - LB/HR	157,000	184,000	250,000
Thermal Load - MW	45.4	52.5	70.9
T/E Ratio	5.0	5.8	7.9

The system energy efficiency in each case is above 85 percent, and in fact approaches the boiler efficiency because no thermal energy is rejected to the condenser cooling water. This assumes, however, that the thermal demand is sufficiently large enough to accommodate this load. Without a condensing turbine in the plant, one must either reduce the electric power generated to match the present thermal load, or generate all of the electric power demand and then blow the costly steam to the atmosphere. This represents the value and significant advantage of a condensing turbine generator with automatic extraction for total energy systems independent of the electric grid system; they are able to match the system's thermal and electrical demands by adjusting the flow to the condensing section of the turbine. The backpressure turbine generators are advantageous for select energy systems if the thermal loads are sufficiently large in relation to the electric loads, and if the electric power requirements in excess of those which match the thermal demand can be purchased through a tie line with the electric grid system.

4.3 Extraction Steam Turbine Performance Map Analysis

The overall system energy efficiency and corresponding thermal/electric ratio were calculated for three single automatic extraction (SAE) turbine generators to illustrate the best operating areas on their performance maps. A program was developed to calculate the system energy efficiency for any point on the map, given the electrical power generated and the extraction steam flow rate. These calculations were based on the following assumptions:

- Boiler efficiency - 88 percent
- Pressure drop, boiler to turbine - 5 percent
- Temperature drop, boiler to turbine - 5°F
- Boiler feedwater temperature - 300°F
- Boiler blowdown - neglected
- Higher heating value of No. 6 fuel oil - 18,500 BTU/LB
- Enthalpy drops across the steam load and the boiler were as previously defined
- Extraction enthalpy performance curves were incorporated for each unit analysed to insure close approximation of the thermal load

Performance information for the 10 and 20 MW rated single automatic extraction (SAE) turbine generator units was supplied by the General Electric Company.[18] This information consisted of the performance maps of throttle flow vs. output for each SAE condensing turbine and the performance curves for the extraction enthalpy in BTU/LBM as a function of the turbine throttle flow in LBM/HR for each unit. Each unit is designed for the same operational conditions: 850 psig/900° FTT throttle conditions, 200 psig SAE and 3.0" HgA condenser pressure. The performance map and extraction enthalpy curve for the 6 MW SAE unit was drawn for the same operational conditions using the above information.

The overall system efficiency and thermal/electric ratio calculations were performed for a complete set of points across the performance maps of the 6, 10 and 20 MW SAE turbine generators, and system efficiencies are plotted on each performance map in figures 4.4 through 4.6 respectively. The extraction steam flow, thermal and electrical loads, thermal/electric ratio and system efficiency of each point are shown for each of the three units in tables 4.2 through 4.4 respectively. The extraction steam performance curves appear in figure 4.7

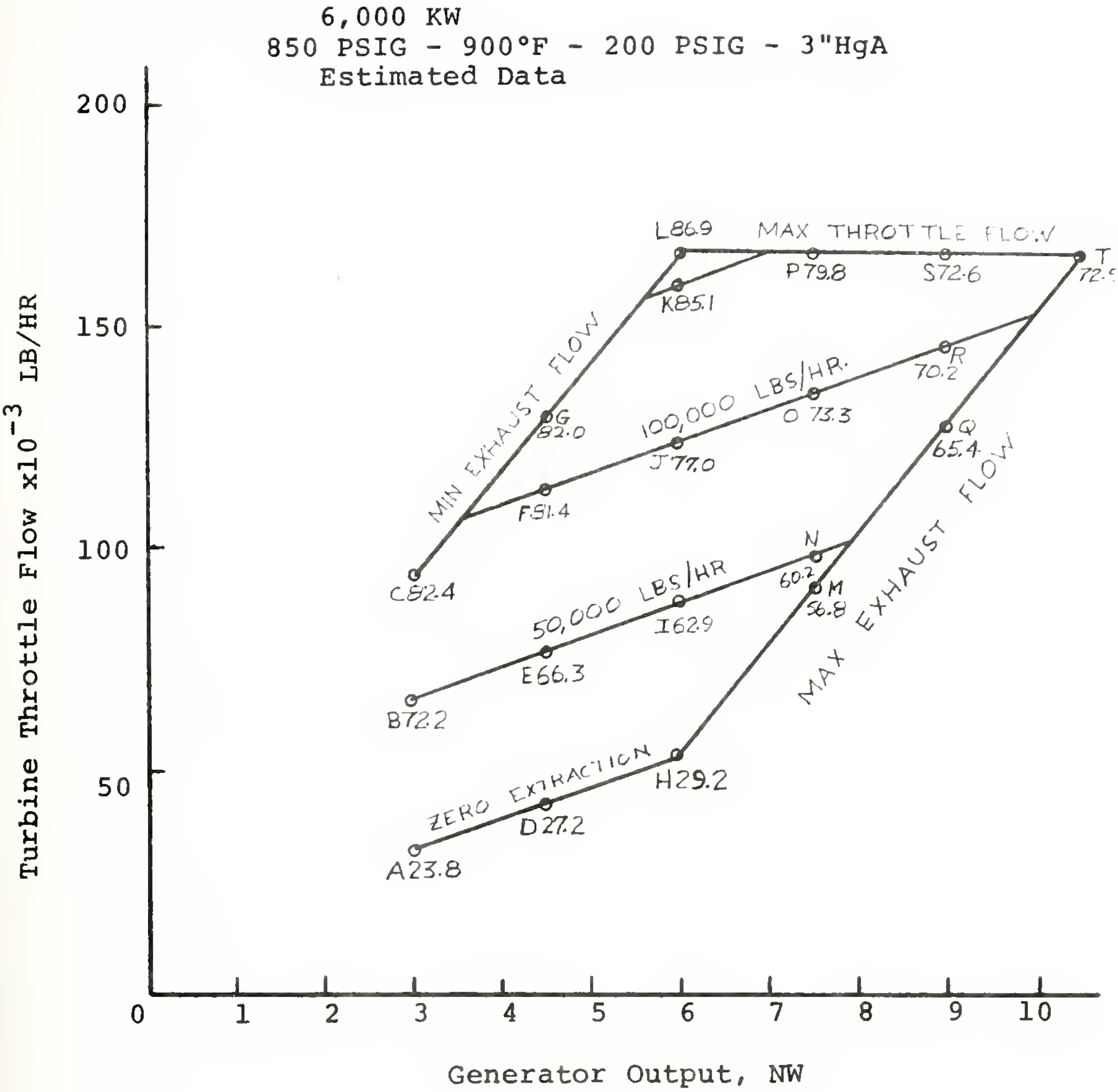


FIGURE 4-4 6 MW SAE Turbine Generator Performance Map Illustrating Overall System Efficiencies

TABLE 4.2 - Performance Data for the 6 MW SAE Turbine Generator Illustrated in Figure 4.4

Point	Extr. Stm. Flow (LB/HR)	Thermal Load (MW)	Electric Load (MW)	Thermal/ Electric Ratio	System Efficiency (%)
A	0	0	3	0	23.76
B	50,000	16.09	3	5.36	72.20
C	85,000	26.92	3	8.97	82.43
D	0	0	4.5	0	27.16
E	50,000	15.91	4.5	3.54	66.32
F	100,000	31.46	4.5	6.99	81.39
G	120,000	37.55	4.5	8.34	81.98
H	0	0	6	0	29.24
I	50,000	15.84	6	2.64	62.89
J	100,000	31.35	6	5.23	76.97
K	150,000	46.72	6	7.79	85.11
L	165,000	51.29	6	8.55	86.95
M	40,000	12.67	7.5	1.69	56.80
N	50,000	15.78	7.5	2.10	60.20
O	100,000	31.26	7.5	4.17	73.32
P	145,000	45.08	7.5	6.01	79.79
Q	75,000	23.49	9	3.61	65.36
R	100,000	31.18	9	3.53	70.22
S	125,000	38.86	9	4.31	72.63
T	120,000	37.30	10.7	3.49	72.86

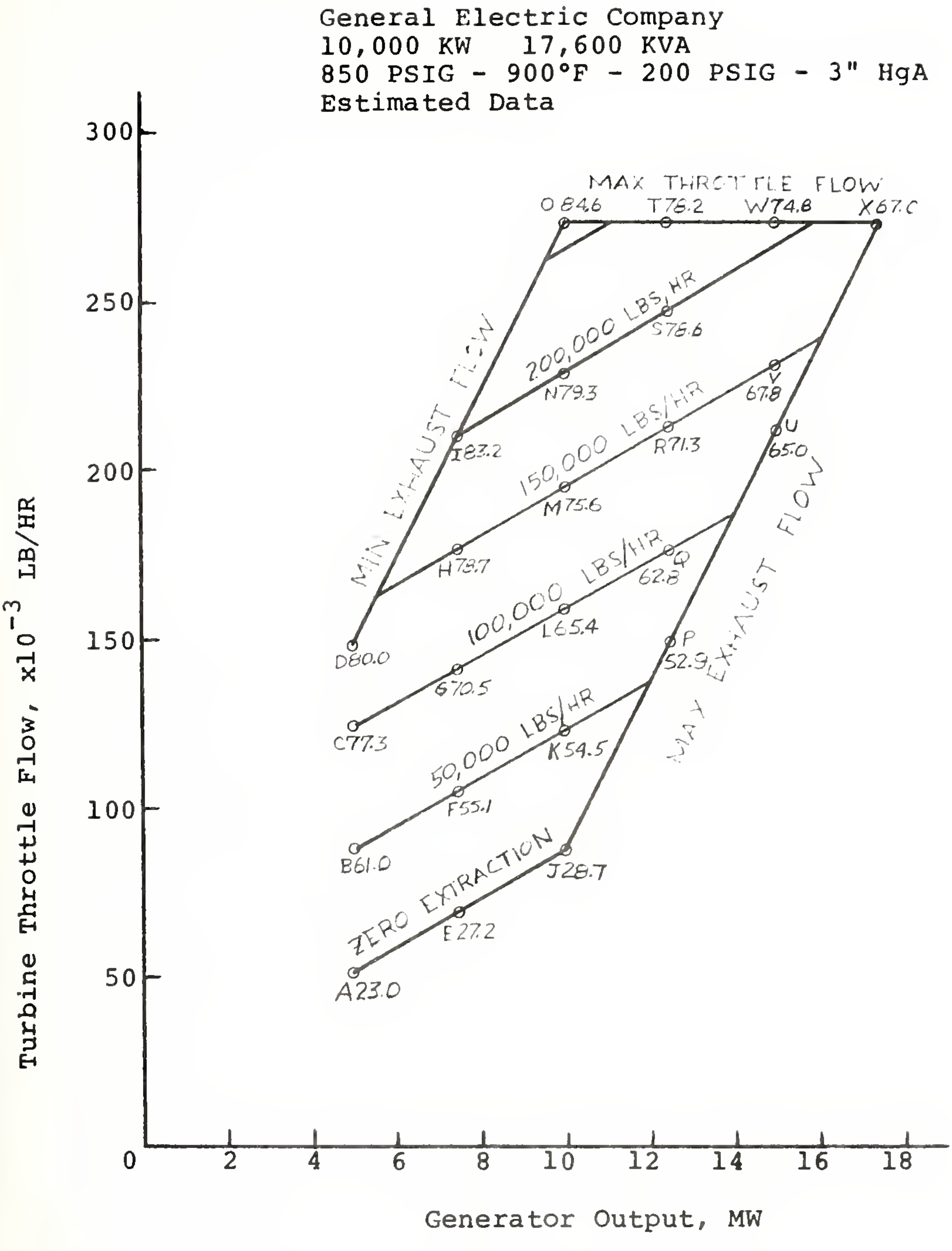


FIGURE 4-5 10 MW SAE Turbine Generator Performance Map Illustrating Overall System Efficiencies

TABLE 4.3 - Performance Data for the 10 MW SAE Turbine Generator Illustrated in Figure 4.5

Point	Extr.Stm. Flow (LB/HR)	Thermal Load (MW)	Electric Load (MW)	Thermal/ Electric Ratio	System Efficiency (%)
A	0	0	5	0	23.04
B	50,000	16.04	5	3.21	60.95
C	100,000	31.61	5	6.32	77.33
D	130,000	40.79	5	8.16	80.04
E	0	0	7.5	0	27.15
F	50,000	15.89	7.5	2.19	55.14
G	100,000	31.42	7.5	4.19	70.47
H	150,000	46.81	7.5	6.24	78.65
I	200,000	62.06	7.5	8.27	83.16
J	0	0	10	0	28.74
K	50,000	15.81	10	1.58	54.51
L	100,000	31.29	10	3.13	65.41
M	150,000	46.67	10	4.67	75.60
N	200,000	61.99	10	6.20	79.34
O	260,000	80.52	10	8.05	84.56
P	60,000	18.81	12.5	1.50	52.90
Q	100,000	31.50	12.5	2.52	62.82
R	150,000	46.59	12.5	3.73	71.31
S	200,000	61.97	12.5	4.96	78.64
T	230,000	71.23	12.5	5.70	78.22
U	125,000	38.82	15	3.11	64.95
V	150,000	46.50	15	3.72	67.77
W	210,000	65.04	15	5.20	74.77
X	175,000	54.20	17.5	4.34	66.98

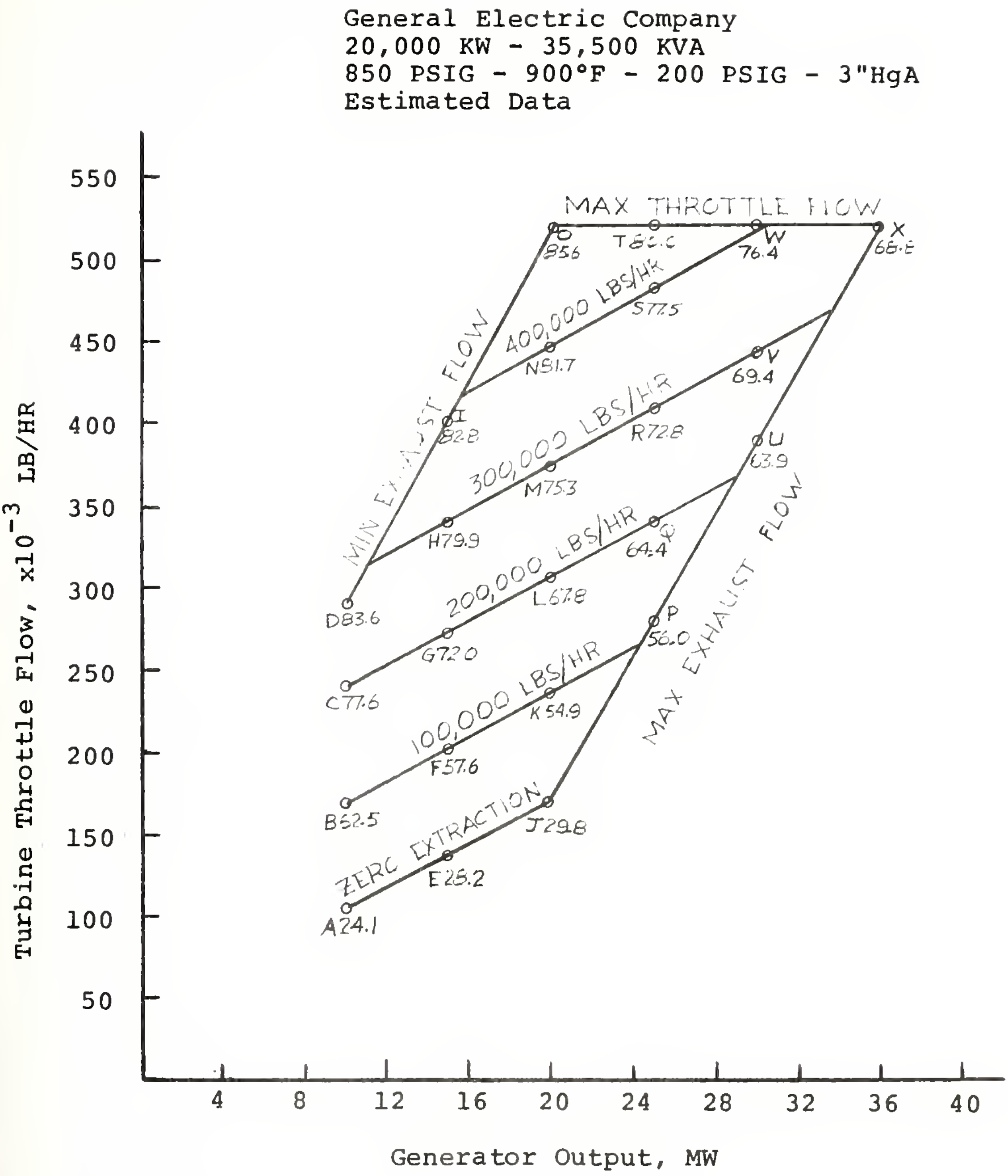


FIGURE 4-6 20 MW SAE Turbine Generator Performance Map Illustrating Overall System Efficiencies

TABLE 4.4 - Performance Data for the 20 MW SAE Turbine Generator Illustrated in Figure 4.6

Point	Extr.Stm. Flow (LB/HR)	Thermal Load (MW)	Electric Load (MW)	Thermal/ Electric Ratio	System Efficiency (%)
A	0	0	10	0	24.14
B	100,000	31.91	10	3.19	62.48
C	200,000	62.82	10	6.28	77.55
D	275,000	85.65	10	8.57	83.60
E	0	0	15	0	28.16
F	100,000	31.61	15	2.11	57.63
G	200,000	62.47	15	4.16	72.05
H	300,000	92.99	15	6.20	79.92
I	380,000	117.35	15	7.82	82.83
J	0	0	20	0	29.82
K	100,000	31.41	20	1.57	54.86
L	200,000	62.23	20	3.11	67.78
M	300,000	92.82	20	4.64	75.25
N	400,000	123.41	20	6.17	81.68
O	500,000	153.97	20	7.70	85.62
P	120,000	37.41	25	1.50	55.99
Q	200,000	61.99	25	2.48	64.38
R	300,000	92.65	25	3.71	72.79
S	400,000	123.29	25	4.93	77.50
T	450,000	138.57	25	5.54	79.99
U	225,000	69.55	30	2.32	63.88
V	300,000	92.55	30	3.09	69.41
W	410,000	126.25	30	4.21	76.41
X	340,000	104.70	36	2.91	68.80

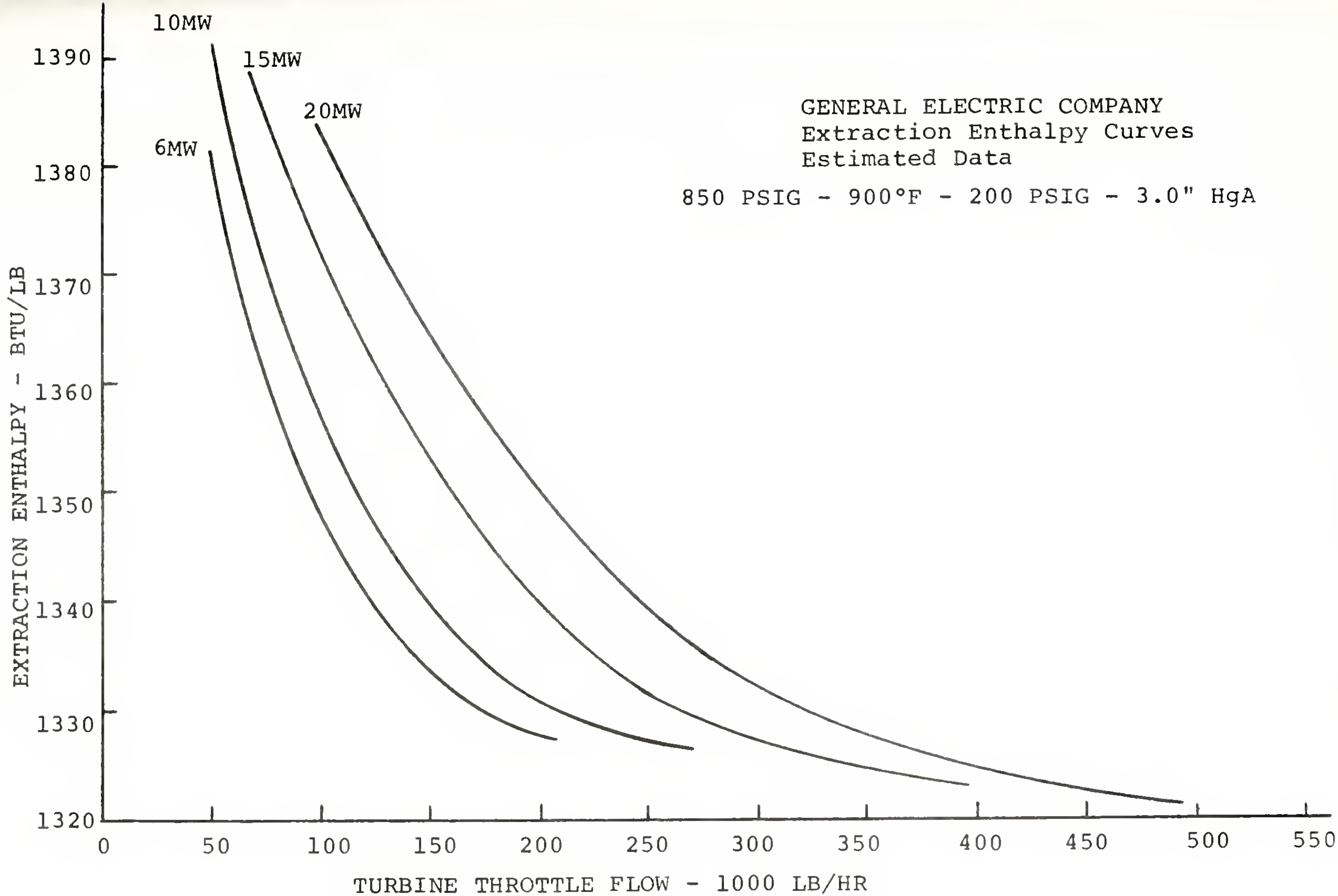


FIGURE 4.7 - Performance Curves of Extraction Enthalpy vs. Turbine Throttle Flow.[18]

The following observations can be made from these figures and tables concerning the extraction steam turbine plants.

The best overall system efficiency obtainable with the units which were analyzed was approximately 87 percent, and is obtained with the smaller 6 MW SAE unit. The thermal/ electric ratio at the best points is above 6.0. In order to achieve overall system efficiencies above 70 percent, the thermal/electric ratio as defined must be above 3.0.

During the conceptual design phase for a total energy system, the facilities annual average electrical load and extraction steam load may be plotted on these performance maps. The location of this point on the performance map will be an indication of the annual overall system efficiency which may be expected from each unit. This can also be used as a guide for selecting the appropriate unit size for the facility, given both the annual average operating loads, and the anticipated maximum and minimum loads (thermal and electrical) which must be supplied.

CHAPTER 5

GAS TURBINE GENERATORS

Gas turbine generators are available in a wide range of sizes, from 300 KW up to approximately 70,000 KW per engine.[19] The gas turbines unique advantages of light weight, compactness and instant startup are offset by their generally low thermal efficiency.

The two types of gas turbines which are marketed are the aircraft derivative gas turbine and the heavy duty industrial gas turbine. The aircraft derivative gas turbine is a modified jet engine, typically of light weight construction. These engines tend to operate at high turbine inlet temperatures and, as a consequence, their operating life between overhauls is not high. The heavy duty gas turbines are designed for industrial applications and operate at more conservative turbine inlet temperatures. For this reason, these units have better maintenance records than the aircraft derivative models.

Heavy duty gas turbines are capable of burning No. 6 fuel oil, provided that the fuel is treated to inhibit corrosion from the vanadium which is present. However, the largest engine manufacturer did not recommend this approach,

and suggested that No. 2 fuel oil should be utilized in design studies for present installations.[20] It is this manufacturer's experience that the increased maintenance costs incurred through the use of the heavy residual oil, regardless of the fuel treatment system installed for it, are not offset by the use of the higher cost distillate fuel. The gas turbine performance information supplied by them was based on the use of distillate fuel oil.[18]

5.1 Gas Turbine Configurations

Gas turbine generators are most widely utilized as emergency or standby generator units because of their quick start capacity. They are also utilized in peaking operations in conjunction with base loaded steam or reciprocating engine plants. Their higher specific fuel consumption is offset in these cases by their lower capital investment cost and their small size and light weight. If the peaks are of short duration, the overall reduction of the system's energy efficiency may be small.

Gas turbine select energy or total energy system installations have generally been limited to industrial applications where the exhaust gases were utilized directly in drying processes, or as preheated combustion air for

supplementary or fully fired boilers producing large quantities of process steam. There are very few environmental total energy systems (providing light, heat and domestic hot water) which utilize only gas turbine prime movers. There are generally operated on natural gas and are owned by the gas companies themselves.[3]

The selection of engine size for a given facility involves establishing an optimum compromise between two sets of opposing factors. The first is that larger engines tend to be more efficient and cost less per unit of shaft output capacity ($/KW) than smaller engines. The second factor is that the use of a large number of smaller engines improves the system reliability, and also allows each individual engine to run closer to full design capacity. In this manner, the engines are operated more economically at their design specific fuel consumption, and also provide exhaust gases at higher temperatures which enhance the heat recovery characteristics of the system. These points were clearly illustrated in the MIT total energy study presented in reference [9].

The system composed of two 9 MW industrial gas turbine generators had a lower annual fuel consumption and higher annual system efficiency than the system utilizing the 17 MW

generator. This was expected because the smaller generators were operating near their best efficiency a greater percentage of the time. In addition, these smaller generators were capable of over producing slightly more steam in relation to the demand than the larger one, which indicates that more waste heat energy was recoverable from this combination than was currently required.

The overall annual average system efficiency for the 9 MW gas turbine generator system, based on the MIT load model demand, was 62.5%. Throughout the year, a total of 15,700,000 lbm of steam in excess of the load requirements at that time were capable of being produced. If this steam could have been utilized at those exact times, the average annual system efficiency would only increase to 63.37%, an increase of less than 1 percent.

The same efficiencies for the 17 MW gas turbine generator system are 60.8% and 61.2% respectively. This system was capable of producing 6,700,000 lbs of steam in excess of the load requirements throughout the year.

5.2 Gas Turbine Waste Heat Recovery Characteristics

The most important thermal characteristics in regards to heat recovery from gas turbines are the balance between shaft output and exhaust heat content, and the temperature

of the exhaust gases. The analysis of these factors for heat recovery purposes is much simpler for gas turbines than for reciprocating engines.

All significant amounts of recoverable waste heat from gas turbines are concentrated in the exhaust gas stream, since gas turbines have no cooling jackets and the thermal capacity of the oil system is low. Gas turbine exhaust temperatures range between 700 and 1000 degrees F. This enables the production of higher pressure steam in greater quantities than is achievable from reciprocating engines of comparable shaft output. It should be noted that even though the fraction of fuel energy which is transformed into exhaust waste heat increases as the turbine load is reduced, the temperature of the exhaust gases is reduced.

The major constraint in the recovery of waste heat from gas turbines is that the exhaust back pressure on the turbines must be kept low, because the gas turbine shaft output will drop sharply with increased back pressure. The sensitivity of gas turbine shaft output to inlet and exhaust duct losses, inlet air temperature, and altitude, are documented in standard references such as Sawyer's Gas Turbine Engineering Handbook [21] and the specific manufacturer's data books and technical manuals.

The variation of air inlet temperature has a marked effect on both exhaust gas flow and exhaust volume, both factors which influence exhaust waste heat recovery. One solution to the adverse effects of high ambient air inlet temperatures, which was utilized in a select energy system installation for the University of California at Davis, was the installation of air coolers in the intake plenums.[22] The air coolers are operated with chill water because of the low cost supply which is readily available at that facility, and the fact that they could cool further with chiller cooling than with evaporative techniques. The system is designed to cool the air to 66°F in the chiller to maintain a temperature of 70°F or better at the compressor inlet.

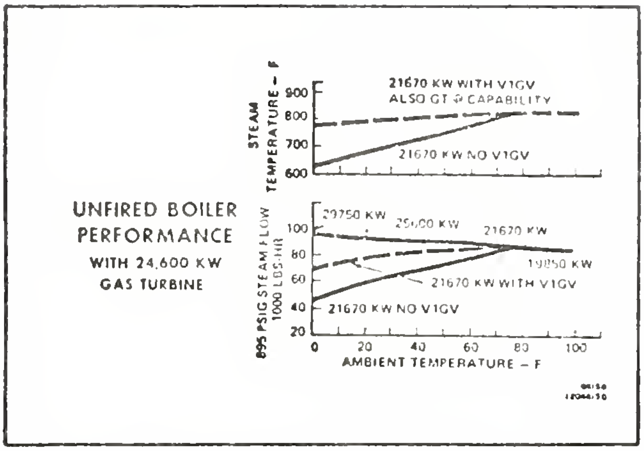
Capability of the simple, open cycle gas turbine increases approximately 3 1/2 to 4 percent for each 10°F decrease in compressor inlet temperature.[23] The LM2500 gas turbine output increases about one percent per °F below the 59°F ISO rating point, up to a maximum of 120 percent power at about 40°F.[24]

For applications involving exhaust heat recovery, the overall plant efficiency may be improved when the gas turbine is always operated at its maximum capability corresponding to the varying site ambient temperatures. For

electrical generation, the low incremental cost per KW available when the ambient temperature is decreased may offset the higher cost KW from alternative sources such as the installation of additional units, or through purchasing from the commercial grid system. This performance characteristic is illustrated in figure 5.1.[24]

Even though waste heat recovery boilers have long been utilized to recover heat in many processes, new concepts of boiler design and performance standards have evolved since the combustion gas turbine has become so widely accepted. In addition to making it economical to recover more heat from the gas turbine exhaust with the finned tube construction, users are finding it economical to generate steam at higher pressures and temperatures than would have been considered with the earlier bare tube designs. The three classifications of waste heat recovery boilers which are utilized with gas turbine installations are unfired, supplementary fired and fully fired units.

The unfired units are the simplest application of waste heat recovery boilers in the gas turbine exhaust. Steam conditions characteristically range from 150 psig saturated to approximately 895 psig - 830°F.[23] Steam temperatures are usually 100°F or more below the gas turbine



BASIS: (1) *24,600-kW ISO gas turbine at sea level site.*

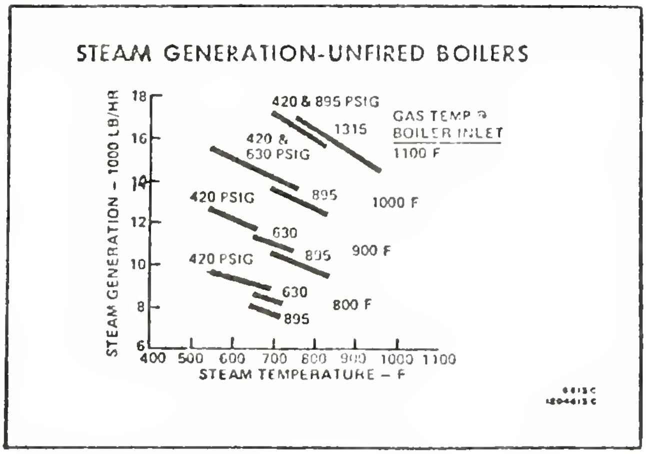
(2) *Boiler designed for 87,500 lb/hr, 895 psig — 830 F at 80 F ambient after allowance for 3% bypass damper leakage, 3% blowdown and 1-1/2% radiation and unaccounted losses with 230 F feedwater.*

FIGURE 5.1 - Typical Gas Turbine Generator and Unfired Waste Heat Recovery Boiler Performance.[24]

exhaust gas temperature. These unfired units can be economically designed to recover approximately 92 percent of the energy in the turbine exhaust gas which is available for steam generation. Higher performance levels are possible. However, the increased cost of heat transfer surface must be evaluated against the additional energy which would be recovered by it.

The steam generation obtainable with unfired waste heat recovery boilers designed for various steam pressures and temperatures while operating at design condition is shown in figure 5.2.[24] The steam generation was calculated on the basis of 100,000 lb/hr of gas turbine exhaust flow through the waste heat boiler. In this manner, the steam generation obtainable for an installation may be estimated based on the particular gas turbine's flow rate.

The 9 MW industrial gas turbine generator described in the previous section was capable of producing approximately 66,000 lb/hr of steam at 200 psig/428°F with 228°F feedwater at rated load. Approximately 116,000 lb/hr at the same conditions was obtainable from the 17 MW generator at the rated load. The thermal/electric ratio in these cases is 2.2 and 2.0 respectively. Industrial gas turbine generators with unfired waste heat recovery boilers are capable of satisfying thermal/electric demand ratios in the range between 1.9 and 2.3.



BASIS: (1) *Steam generation is per 100,000 lb/hr boiler gas flow.*

(2) *Figures on curves are superheater outlet pressures.*

(3) *92% effectiveness – 3% blowdown and 1-1/2% radiation and unaccounted losses.*

FIGURE 5.2 - Steam Generation Obtainable with Unfired Waste Heat Recovery Boilers.[24]

The oxygen content of the gas turbine exhaust usually permits supplementary fuel firing ahead of the boiler to increase the steam production rates relative to an unfired unit. Within the industry, supplementary fired units are usually defined as units which are fired to an average gas temperature of 1800°F or less.[23] Since the turbine exhaust is essentially preheated combustion air, the fuel consumption of the supplementary fired exhaust heat recovery boiler is less than that required for a power boiler providing the same incremental increase in steam generation. For example, the fuel consumption for a waste heat boiler which is fired to 1400°F average gas temperature into the unit will be 15 to 20 percent less than for a natural gas ambient air fired power boiler (84 percent efficient) providing the same incremental increase in steam production.[23]

A fully fired boiler is defined as a unit having the same amount of oxygen in its stack gases as an ambient air fired power boiler.[23] The steam production rates for fully fired boilers (10 percent excess air) usually range between 6 and 7.5 times the unfired boiler steam production rate. The actual increase is a function of the amount of oxygen remaining for combustion and the gas turbine exhaust temperature. Again, due to the use of preheated combustion air, the fuel requirements for fully fired units will usually range between 7.5 and 8 percent less than that of an ambient air fired boiler providing the same incremental steam production.

CHAPTER 6

RECIPROCATING INTERNAL COMBUSTION ENGINE GENERATORS

Reciprocating internal combustion (IC) engines are available in a wide range of sizes up to approximately 7,000 KW per engine. In this power range, the diesel engines fuel consumption is unmatched by any other prime mover. Steam generation up to 200 psig in some cases may be provided by combination waste heat boiler/silencers installed in the exhaust system. Large power European low and medium speed diesel engines are now becoming available in the United States through licensing arrangements with American companies. Many of these engines have been designed for operation on No. 6 residual fuel oil. This chapter describes the types of engines in this category and the methods by which their waste heat may be economically recovered in a total energy system.

6.1 Engine and System Configurations

The term reciprocating internal combustion engine covers a wide range of prime movers. Natural gas fueled engines, operating on both the diesel and Otto cycles are the most numerous due to the artificially low cost of natural gas, the absence of transportation and storage problems with the fuel, and an aggressive marketing campaign by the gas industry.

Dual fuel engines are designed for operation with either natural gas or light distillate fuel oils, typically No. 2 diesel oil. They generally utilize natural gas on an interruptable supply basis when it is available, and then shift to diesel oil when the supply is curtailed. These engines are not capable of operation with the heavy residual oils.

Duing the recent years, several large European diesel manufacturers have developed low and medium speed engines for operation on the heavier residual fuels. These engines have been developed to compete with the steam turbine both in the marine industry and in shoreside electrical generation facilities.

Gasoline fueled engines are not generally used for electrical power generation.

IC engines are utilized in various system configurations from emergency or standby generator units to total energy system installations independent of the utility grid. As emergency or standby units, they are capable of relatively quick starts by electrical or pneumatic means, actuated by low voltage relays from the main switchboard.

Diesel engine generators are preferred for select or total energy systems because of their favorable off-design fuel consumption performance. Diesel engines are recommended

over gas reciprocating engines because of their potential for using standard naval ship and aircraft fuels. It is anticipated that the cost of natural gas will experience a larger long term price increase than will distillate type diesel or residual fuels.

6.2 Waste Heat Recovery Techniques

All reciprocating IC engines use similar waste heat recovery techniques. The recovery of exhaust gas heat, engine jacket heat and possible oil/aftercooler heat are all significant and may be combined in many ways.

The exhaust gases provide between 30 and 40 percent of the recoverable waste heat in existing engines, with the proportion rising in larger engines. The exhaust gases also provide waste heat at the highest temperatures, and are thus the source utilized for high pressure steam (up to 200 psig in some cases). The exhaust waste heat boiler also serves as the engine silencer. This will generally have an acoustically lined exhaust by-pass around the boiler to permit engine operation without heat recovery in the event of problems with the boiler.

The 6.9 MW Colt Pielstick PC 2.3 diesel engine generators analyzed for the MIT total energy study [9,10] were capable of generating approximately 12,500 lb/hr of steam at

200 psig/428°F with 228°F feedwater at rated load. This represents a thermal/electric ratio of 0.55. Figure 6.1 illustrates the thermal steam power obtainable as a function of the electric power generated by several of these engines.[15]

The amount of exhaust heat recoverable from an engine is a function of the amount of heat available in the gases and the exhaust gas temperature. Engine types vary widely in their exhaust temperature characteristics. The effect of the following four variables should be taken into account in the design of an exhaust heat recovery system.

For two-stroke vs. four-stroke cycles, the exhaust temperatures for the two-stroke engines tend to be much lower than the four-stroke engines due to the excess scavenging air flow through the engine. Exhaust heat recovery from a two-stroke engine at low load is particularly difficult due to the small temperature drop across the heat exchanger.

Spark ignited, natural gas fueled engines have much higher exhaust temperatures than diesel engines due to the greater efficiency of the diesel cycle compared with the Otto cycle and the differences in the fuel characteristics. Exhaust heat recovery from the diesel engines may also be limited at low loads, as described above.

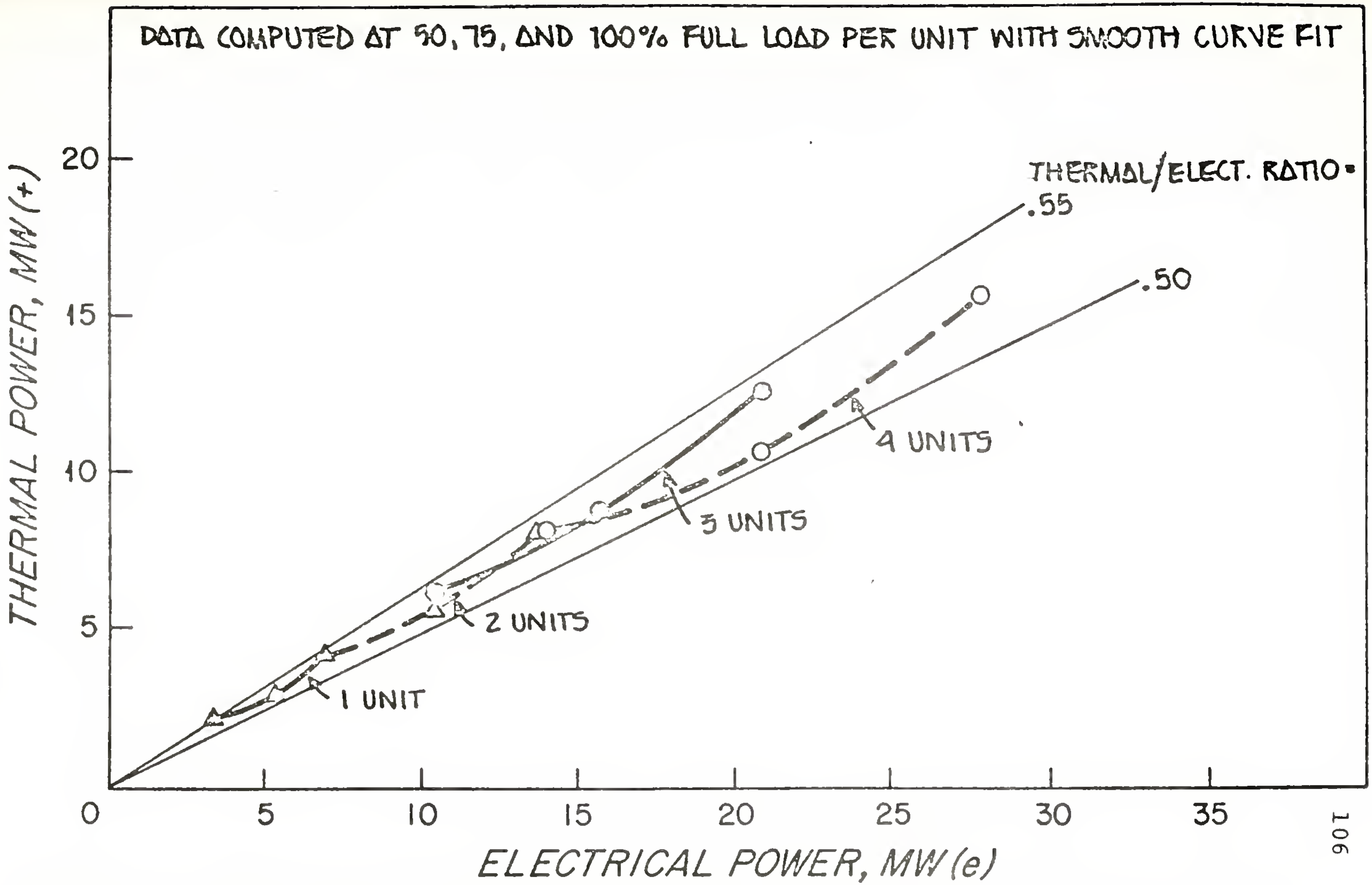


FIGURE 6.1 - Performance Characteristics for Colt Pielstick PC 2.3 Stationary Diesel Engine Generators.[15]

Increasing the jacket coolant temperature will cause a small increase in the exhaust gas temperature in all engine types. The exhaust gas heat content is also increased, so that exhaust heat recovery will always increase with an increase in the jacket temperature. Specific methods of jacket cooling and jacket heat recovery are described in subsequent paragraphs.

Increasing engine speed will generally increase the exhaust temperature and heat content, so that greater heat recovery will be achievable at higher engine speeds.

The jacket cooling water provides between 40 and 60 percent of the recoverable waste heat from the engine, with the proportion dropping in larger engines. The maximum coolant temperature is primarily limited by the requirement for adequate heat removal from the cylinders and cylinder heads, and also by the temperature limitations of the water sealant materials. The present maximum coolant temperature is approximately 250°F, which is adequate to provide 12 to 15 psig steam for local space or feedwater heating, or for absorption air conditioning. The two types of jacket heat recovery methods are liquid-to-liquid heat exchangers and ebullient heat recovery systems.

Liquid-to-liquid heat exchangers keep the engine coolant in a liquid state under pressure while transferring heat to the heat recovery water loop.

Ebullient heat recovery systems effectively utilize the engine block as a boiler. They generally consist of a direct line between the engine cooling jacket and a steam separation tank located above the engine. The engine cooling water is allowed to flash into vapor as it rises from the cooling jacket to the higher tank. The hydrostatic pressure of the water column in the line prevents excessive steam formation within the engine, with subsequent engine overheating. The ebullient cooling eliminates the need for a heat exchanger. High heat transfer rates can be effected since the engine is cooled by the transfer of latent as well as sensible heat.

The effective heat recovery from the engine lube oil coolers is limited because of the relatively small quantity of heat available and because of the low recovery temperatures. Hot water heating is the usual application where it is used.

CHAPTER 7

ENVIRONMENTAL IMPACT FACTORS

The environmental factors which can impact the successful application of a total energy system installation are considered in this chapter. The purpose is to point out those areas of environmental impact which are peculiar or significant to the total energy system installation.

There are two distinct types of air quality standards; Emission Limitations and Ambient Air Quality Standards. The Emission Limitations are a measure of the pollutants exhausted from the plant to the environment through the stack. The Ambient Air Quality Standards are a measure of the pollutant levels in the ambient air surrounding the plant facility. It represents the level of pollutants already existing in the ambient air, in addition to the effect of the diffusion of the exhaust gases from the proposed facility into this surrounding air.

7.1 Federal Air Quality Standards

National standards have been set by the Federal government. These are the National Ambient Air Quality Standards and the Emission Limitations or New Source Performance Standards which are set by the Federal Environmental

Protection Agency. The New Source Performance Standards are promulgated by the EPA, as directed by the Clean Air Act. They establish a maximum level of pollutant emissions per unit of heat input.

The national standards for the three types of prime movers applicable to total energy system applications are illustrated in the following tables. Table 7.1 is a summary of the Federal Emission Limitations for boilers (external combustion sources).[25] Table 7.2 illustrates the Emission Limitation factors for electric utility gas turbine generators and the operating cycle upon which these composite emission factors were based.[26] Table 7.3 is a summary of the Federal EPA New Source Performance Standards for stationary diesel engine generators which are expected to become effective in 1979.[27] The National Ambient Air Quality Standards in the United States are presented in Table 7.4.[28]

7.2 State and Local Standards

In addition to the federal air quality standards, any total energy plant installed at a U.S. Naval facility must comply with the applicable state and local regulations for its particular location. Each state may have its own set of Emission Limitations and Ambient Air Quality Standards

Table 1.3-1. EMISSION FACTORS FOR FUEL OIL COMBUSTION
EMISSION FACTOR RATING: A

Pollutant	Power plant, Residual oil, lb/10^3 gal	Power plant, Residual oil, kg/10^3 liter	Industrial and commercial, Residual oil, lb/10^3 gal	Industrial and commercial, Residual oil, kg/10^3 liter	Industrial and commercial, Distillate oil, lb/10^3 gal	Industrial and commercial, Distillate oil, kg/10^3 liter	Domestic, Distillate oil, lb/10^3 gal	Domestic, Distillate oil, kg/10^3 liter
Particulate[b]	c	c	c	c	2	0.25	2.5	0.31
Sulfur dioxide[d]	157S	19S	157S	19S	142S	17S	142S	17S
Sulfur trioxide[d]	2S	0.25S	2S	0.25S	2S	0.25S	2S	0.25S
Carbon monoxide[e]	5	0.63	5	0.63	5	0.63	5	0.63
Hydrocarbons (total, as CH_4)[f]	1	0.12	1	0.12	1	0.12	1	0.12
Nitrogen oxides (total, as NO_2)[g]	105(50)[h,i]	12.6(6.25)[h,i]	60[j]	7.5[j]	22	2.8	18	2.3

Type of boiler[a]

[a]Boilers can be classified, roughly, according to their gross (higher) heat input rate, as shown below.
Power plant (utility) boilers: $>250 \times 10^6$ Btu/hr ($>63 \times 10^6$ kg-cal/hr)
Industrial boilers: $>15 \times 10^6$, but $<250 \times 10^6$ Btu/hr ($>3.7 \times 10^6$, but $<63 \times 10^6$ kg-cal/hr)
Commercial boilers: $>0.5 \times 10^6$, but $<15 \times 10^6$ Btu/hr ($>0.13 \times 10^6$, but $<3.7 \times 10^6$ kg-cal/hr)
Domestic (residential) boilers: $<0.5 \times 10^6$ Btu/hr ($<0.13 \times 10^6$ kg-cal/hr)

[b]Based on References 3 through 6. Particulate is defined in this section as that material collected by EPA Method 5 (front half catch)[7].

[c]Particulate emission factors for residual oil combustion are best described, on the average, as a function of fuel oil grade and sulfur content, as shown below.
Grade 6 oil: lb/10^3 gal = 10 (S) + 3
[kg/10^3 liter = 1.25 (S) + 0.38]
Where: S is the percentage, by weight, of sulfur in the oil
Grade 5 oil: 10 lb/10^3 gal (1.25 kg/10^3 liter)
Grade 4 oil: 7 lb/10^3 gal (0.88 kg/10^3 liter)

[d]Based on References 1 through 5. S is the percentage, by weight, of sulfur in the oil.

[e]Based on References 3 through 5 and 8 through 10. Carbon monoxide emissions may increase by a factor of 10 to 100 if a unit is improperly operated or not well maintained.

[f]Based on References 1, 3 through 5, and 10. Hydrocarbon emissions are generally negligible unless unit is improperly operated or not well maintained, in which case emissions may increase by several orders of magnitude.

[g]Based on References 1 through 5 and 8 through 11.

[h]Use 50 lb/10^3 gal (6.25 kg/10^3 liter) for tangentially fired boilers and 105 lb/10^3 gal (12.6 kg/10^3 liter) for all others, at full load, and normal (>15 percent) excess air. At reduced loads, NO_x emissions are reduced by 0.5 to 1 percent, on the average, for every percentage reduction in boiler load.

[i]Several combustion modifications can be employed for NO_x reduction (1) limited excess air firing can reduce NO_x emissions by 5 to 30 percent, (2) staged combustion can reduce NO_x emissions by 20 to 45 percent, and (3) flue gas recirculation can reduce NO_x emissions by 10 to 45 percent. Combinations of the modifications have been employed to reduce NO_x emissions by as much as 60 percent in certain boilers. See section 1.4 for a discussion of these NO_x-reducing techniques.

[j]Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are strongly dependent on the fuel nitrogen content and can be estimated more accurately by the following empirical relationship:
lb $NO_2/10^3$ gal = 22 + 400 $(N)^2$
[kg $NO_2/10^3$ liters = 2.75 + 50 $(N)^2$]
Where: N is the percentage, by weight, of nitrogen in the oil. Note: For residual oils having high (>0.5%, by weight) nitrogen contents, one should use 120 lb $NO_2/10^3$ gal (15 kg $NO_2/10^3$ liter) as an emission factor.

TABLE 7.1 - Federal EPA Emission Limitations for Boilers (External Combustion Sources) [25]

Table 3.3.1-1. TYPICAL OPERATING CYCLE FOR ELECTRIC UTILITY TURBINES

Condition, % of rated power	Percent operating time spent at condition	Time at condition based on 4.8-hr day: hours	Time at condition based on 4.8-hr day: minutes	Contribution to load factor at condition
0	15	0.72	43	0.00 x 0.15 = 0.0
25	2	0.10	6	0.25 x 0.02 = 0.005
50	2	0.10	6	0.50 x 0.02 = 0.010
75	2	0.10	6	0.75 x 0.02 = 0.015
100 (base)	60	2.88	173	1.0 x 0.60 = 0.60
125 (peak)	19	0.91	55	1.25 x 0.19 = 0.238
		4.81	289	Load factor = 0.868

The operating cycle in Table 3.3.1-1 is used to compute emission factors, although it is only an estimate of actual operating patterns.

Table 3.3.1-2. COMPOSITE EMISSION FACTORS FOR 1971 POPULATION OF ELECTRIC UTILITY TURBINES
EMISSION FACTOR RATING: B

Time basis	Nitrogen oxides	Hydro-carbons	Carbon Monoxide	Partic-ulate	Sulfur oxides
Entire population					
lb/hr rated load[a]	8.84	0.79	2.18	0.52	0.33
kg/hr rated load	4.01	0.36	0.99	0.24	0.15
Gas-fired only					
lb/hr rated load	7.81	0.79	2.18	0.27	0.098
kg/hr rated load	3.54	0.36	0.99	0.12	0.044
Oil-fired only					
lb/hr rated load	9.60	0.79	2.18	0.71	0.50
kg/hr rated load	4.35	0.36	0.99	0.32	0.23
Fuel basis					
Gas-fired only					
$lb/10^6 ft^3$ gas	413.	42.	115.	14.	940S[b]
$kg/10^6 m^3$ gas	6615.	673.	1842.	224.	15,000S
Oil-fired only					
$lb/10^3$ gal oil	67.8	5.57	15.4	5.0	140S
$kg/10^3$ liter oil	8.13	0.668	1.85	0.60	16.8S

[a] Rated load expressed in megawatts.
[b] S is the percentage sulfur. Example: If the factor is 940 and the sulfur content is 0.01 percent, the sulfur oxides emitted would be 940 times 0.01, or 9.4 $lb/10^6 ft^3$ gas.

Table 3.3.1-2 is the resultant composite emission factors based on the operating cycle of Table 3.3.1-1 and the 1971 population of electric utility turbines.

TABLE 7.2 - Federal EPA Emission Limitations for Stationary Gas Turbine Generators.[26]

TABLE 7.3 - Federal EPA New Source Performance Standards for Stationary Diesel Engine Generators, Effective Beginning in 1979 [27]

Pollutant	Standard
HC_T (Total Hydrocarbons)	$\leq$ 1.5 g/BHP-hr
CO	$\leq$ 25 g/BHP-hr
NO_x and HC_T (Combined)	$\leq$ 10 g/BHP-hr

TABLE 7.4 - National Ambient Air Quality Standards in the United States [28]

Pollutant	Standard
Particulate Matter	75 μg/m^3, annual geometric mean 260 μg/m^3, max. 24-hr value may occur once each year.
SO_2	80 μg/m^3, annual arithmetic mean 365 μg/m^3, max. 24-hr value may occur once each year.
CO	10 mg/m^3, max 8-hr value may occur once each year. 40 mg/m^3, max 1-hr value may occur once each year.
HC_T	160 μg/m^3, max level that may occur 6-9 a.m. once each year.
NO_x	100 μg/m^3, annual arithmetic mean

similar to the federal standards. There may also be local regulations pertaining to such items as the types of fuels which are permitted for use within city limits, etc. Those regulations which are applicable for total energy systems in the Commonwealth of Massachusetts are presented as an example of these state standards.

Table 7.5 provides a summary of the Commonwealth of Massachusetts Emission Limitations which are applicable to any total energy system installation.[29] These Emission Limitations specified by the Commonwealth of Massachusetts are applicable to any type of installation, i.e., boiler and steam plant, and diesel engine or gas turbine generators, except where specifically noted for a particular pollutant emission.

The Commonwealth of Massachusetts does not specify any limits on the quantity of SO_2 emitted by the facility, but rather specifies limits on the quantity of sulfur which can be present in the fuels which are burned. The sulfur content of No. 6 fuel oil must be less than 0.28 pounds per million BTU heat release (approximately equivalent to 0.5% by weight sulfur content). The sulfur content of No. 2 fuel oil is required to be less than 0.17 pounds of sulfur per million BTU heat release potential (approximately 0.3% by weight sulfur content).

TABLE 7.5 - Commonwealth of Massachusetts Emission Limitations for Fossil Fuel Utilization Facilities.[29]

	Facility Size [Million Btu/hr]	Emission Limitation [lbs/million Btu]	
		New	Existing
Particulates:	3-250	0.10	0.12
	greater than 250	0.05	0.12
Oxides of Nitrogen:	greater than 250	0.3*	

***This limitation does not apply to gas turbine or diesel engines.**

If the total particulate emissions for any facility (including old and new equipment) is greater than 100 tons/year, the proposed design is subject to an interpretive agreement by the Commonwealth. This interpretive agreement is a compromise arrangement, such that for every pound of particulate emissions produced by the facility over the 100 tons/year maximum limit, old equipment must be retired until the particulate emissions of the facility are reduced, pound for pound, to the 100 tons/year standard level.

It should be noted that the NO_x emission limitations do not apply to gas turbines and diesel engines. This is because installations of these types are rated at relatively low power levels and represented a small percentage contribution to the overall pollution of the environment when the regulations were established. The Emission Limitations of the Commonwealth of Massachusetts are presently directed towards reducing the pollutant emissions primarily from power and industrial boilers. Control of the emissions from diesel engines and gas turbines is through new regulations and limits on the Ambient Air Quality Standards.

The Federal EPA presently does not have a maximum one hour standard for NO_x Ambient Air Quality, but is mandated by the Clean Air Act to adopt a standard by Fall, 1978. The

Commonwealth of Massachusetts has recently adopted a standard for NO_x emissions of 200 $\mu g/m^3$ for a one hour maximum as a temporary measure. It is expected that this 200 $\mu g/m^3$ is stricter than the level that the Federal EPA will adopt. A one hour standard of about 400 ± 50 $\mu g/m^3$ for NO_x emissions is expected to be adopted by the Federal EPA. By state law, the Commonwealth of Massachusetts cannot adopt any standards for ambient air quality which are stricter than those specified by the Federal EPA, and so it is expected that this new temporary measure will be superceded by the Federal standard.

The facility sizes listed in the Massachusetts Emission Limitation, Table 7.5, assume that all of the installed equipment is operated at maximum rated capacity. This may result in a penalty against total energy systems which are required to have extra reserve capacity equipment in order to operate in a reliable manner independent of the local utility grid.

7.3 Summary of Environmental Impacts

In addition to the air quality standards just described, any total energy system installation must comply with the applicable water quality standards, ambient noise level standards, and other impact standards such as the effect on traffic and roads due to increased fuel delivery by trucks or railroads, etc.

It should be obvious from the above information that the feasibility of a project of this nature, from the standpoint of environmental impact, is a dynamic factor which is subject to change with time. The environmental impact standards are influenced by political and public pressure, and therefore cannot be as easily quantified as the other engineering and economic factors. The exact feasibility determination can only be made during the detailed preliminary design phase.

To determine whether or not any given plant will be able to meet the Ambient Air Quality Standards, much more data and specific plant configuration details must be developed. Additional information such as the present air quality around the selected plant site has to be determined. The exact pollutant emissions from the equipment must be known, the preliminary height estimates of the smoke stacks to be installed, and a determination of the occupancy of buildings in the area surrounding the plant site must all be analyzed.

CHAPTER 8

CONCLUSIONS AND RECOMMENDATIONS

Total energy systems have been documented in other countries as well established energy system alternatives to central station power generation. Total energy is very much a commercial system in this country, and therefore, there should be a substantial research and development effort toward improving total energy as a system. The background of the total energy concept and the history of its development in this country should be considered in order to explain the thrust of future research and development which is required.

8.1 Background of the Total Energy Concept

Total energy systems were developed as a marketing concept by the natural gas industry in the early 1960's.[4] During the 1960's there was fierce competition between the gas and electric utilities in all segments of the energy market. Total energy was the natural gas industry's answer to central station power generation. It was defined as on-site power generation with waste heat recovery, and was adopted by the gas industry as a national marketing policy.

Normally, the American Gas Association would have been the focal point of joint industry efforts to develop this concept. However, the combination companies (those

companies selling both electricity and gas) who contributed approximately 40 percent of AGA's operating funds, reduced the effectiveness of AGA in organizing substantial marketing and technology development programs. In 1965, the Group to Advance Total Energy (GATE) was formed by approximately 30 straight gas utility companies to develop the marketing programs, promotional literature and sales tools required to assist the utilities in marketing the total energy concept.

An examination of the research program of AGA since 1964 showed relatively little support for total energy research programs.[4] The AGA studied many proposals to conduct research in total energy, particularly energy storage, solar energy augmented systems, prime mover development, etc. However, these projects did not receive any financial support. The only major research program initiated by AGA was with the Sundstrand Corporation to develop their organic Rankine power system into a modular total energy package in the 25 KW to 100 KW size range.

Except for the Sundstrand program, there has been no concerted research effort towards the advancement of total energy systems. While there has been a substantial amount of research into the components that make up a total energy system, the purpose of that research has been to improve the performance of those components themselves, and the total

energy system performance has benefited only incidently. In considering the new role of total energy systems in this country as one method to improve fossil fuel energy conservation, the background development of the total energy concept suggests a need for a more concerted effort towards a mission-oriented research and development program of total energy as a system.

8.2 Research Requirements for Total Energy

The key technical challenges of total energy systems are in the areas of the overall system design, prime mover development, and the heat recovery and space conditioning hardware. Some of the specific technical problems relating to the successful application of total energy systems are discussed in the following sections.

8.2.1 System Deficiencies

The most important problem associated with the successful design of a total energy system from the very beginning is simultaneously matching the electric power and waste heat output of the system with the electric power demand of the facility, and the facilities' ability to utilize this waste heat in the quantity available at that time. The two major points of this problem are:

1) The ability to accurately predict the facilities' hourly energy demands (electric power, space heating and cooling, and hot water requirements).
2) The ability to accurately predict the full and especially part load performance of the prime movers to determine how much waste heat will actually be available.

The importance of obtaining valid load profile data for the facility, on an hour by hour daily basis, and exact performance data for the prime movers and other components cannot be overemphasized. The load profile data must be site specific for each individual facility and cannot be the result of data generalization from other facilities. The load model program developed at MIT, which was described in Chapter 2, predicted the Institute's fuel consumption within 1.4% for the entire year, and within 0.1% for six of the twelve months. The accuracy of these fuel predictions was the result of accurately matching the thermal and electrical loads on an hour by hour basis for the entire year.

The other major problem with total energy system design is the integration of the various components into a system, and the automatic controls which are required to monitor and operate the system. The responsibility for this aspect of the system design rests primarily with the engineers developing the system. Even though the individual components may be matched with their loads, if they are not compatible with each other or the automatic controls are not properly designed, total energy as a system will not be successful.

8.2.2 Prime Mover Developments

In addition to accurately predicting the off design performance of the various prime movers generally utilized for total energy system installations, their operational performance and reliability must be considered. These prime movers must be able to operate on a continuous basis at maximum load levels. They are required to operate automatically and provide uninterrupted electrical service. Cost and efficiency dominate the technological challenge for total energy system prime movers.

The technical challenges in these areas are the design of prime movers with low initial cost and low operating and maintenance costs in conjunction with increased

operating times between routine maintenance functions and overhauls to provide increased engine availability and system reliability. The following are examples of some of the technical problems encountered with the prime movers in existing total energy systems.[4]

The interior of IC engine cooling jackets are difficult to clean. This has resulted in insufficient cooling water flow which has caused engine block warpage in several cases. The engine jackets are sensitive to hot spots caused by sludge accumulation encountered in ebullient or steam heat recovery systems. Engine head gaskets and other seals also have a tendency to fail at these higher operating temperatures.

Gas turbine generators have experienced thrust bearing failures, lube oil coagulation, nozzle and combustion cracks, and oil and dirt accumulation which has caused imbalance in the bearing systems or turbine blading.

8.2.3 Waste Heat Recovery System Requirements

It is easy to show substantial energy savings and high levels of system feasibility for the total energy concept in the winter months, when there is a relatively high demand for space heating utilizing the waste heat from electrical power generation, assuming that there is a

reasonable match between the facilities' electrical and space heating demands. However, during the summer months, the majority of this waste heat must be utilized for air conditioning and refrigeration systems through heat actuated cooling cycles.

Only lithium bromide absorption cooling systems are manufactured in the sizes required by total energy system installations. The major advantage of lithium bromide absorption is that the cooling cycle will function with heat imputs to the lithium bromide generator as low as 200-220°F. Therefore low pressure steam from ebullient cooling systems or steam turbine exhausts are satisfactory heat sources. The following are some of the major disadvantages of the absorption cooling systems and the areas requiring technological development.[4]

The efficiency of lithium bromide absorption cooling units is relatively low. They require approximately twice the heat energy input of a centrifugal refrigeration unit per ton of cooling. This low efficiency may result in the need for supplemental heat input, in addition to the available waste heat.

The initial cost of an absorption unit is also higher per ton of refrigeration than comparable electric reciprocating or centrifugal systems.

The service failure rate of absorption cooling units in the past has been extremely high, resulting in low unit availabilities and system reliabilities. The major problem has been corrosion. This problem has been reduced through the development of good corrosion inhibitors and the thorough testing of manufactured units to insure satisfactory operation under a high vacuum.

These are the technological problems and challenges of the air conditioning and refrigeration equipment. With regards to waste heat recovery boilers for steam production, the problem is one of matching equipment in the system. For example, the General Electric Company manufactures waste heat recovery boilers for their industrial gas turbines, but only for industrial process applications or when installed in their STAG* cycle to drive a steam turbine in parallel with the gas turbine.[20] They claim that they cannot manufacture these boilers on a competitive basis with the other boiler manufacturers, and so they do not offer them for sale with the gas turbines for total energy system installations. Therefore, in the MIT total energy system design study [9,10], Maxim waste heat recovery boiler/silencers manufactured by the Riley Stoker Company were proposed for both the gas turbine and diesel engine generator system conceptual

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*Trademark of the General Electric Company, reference [21].

designs. This is another example illustrating how the responsibility for total energy system design and integration rests primarily with engineers developing the system, and not with the major equipment manufacturers.

8.3 Applicability to Naval Installations

The economic and fuel conservational advantages of the total energy system concept have been proven both in design studies and in many installations. They should prove to be advantageous at naval training facilities such as the one at Great Lakes, Illinois, which demonstrated load profiles similar to those at MIT.[2,9] They should also be considered for installation at facilities which have large thermal steam demands such as naval air stations, ship stations and shipyards as illustrated in table 2.1.

This depends of course on the relative occurrance of the electrical and thermal loads on an hour by hour basis. A concerted effort must be made to develop these daily load profiles for each individual installation, and to match the off-design performance of the prime movers in relation to these loads.

The total energy concept requires careful development of the engineering system from the beginning of the conceptual design, not only in matching the prime movers with the loads

but in selecting the waste heat recovery boilers for the engines and the automatic controls which are required to monitor and operate the system.

The environmental impacts of a total energy system, with respect to air pollution, are actually no more complicated than for a conventional on-site electrical generation system. The thermal pollution is actually reduced somewhat due to the utilization of the waste heat produced from the electric power generation.

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